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, 2022

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, 2022 was $5.9 billion (based on the closing price of $61.61 per share as of the last business day of the fiscal quarter ending June 30, 2022).

As of February 14, 2023, there were 88,389,372 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 2023 Annual Meeting of Stockholders.

PDC ENERGY, INC.
2022 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 Energy", "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; drilling locations, zones and growth opportunities; impacts of Colorado political matters, including initiatives influencing our ability to continue to obtain permits and the timing of such receipt; 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; adequacy of midstream infrastructure; the potential return of capital to shareholders through buyback of shares and/or payments of dividends; expected impact from emission reduction initiatives; risk of our counterparties non-performance on derivative instruments; and our ability to 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:

- market and commodity price volatility, widening price differentials and related impacts to the Company, including decreased revenue, income and cash flow, write-downs and impairments and decreased availability of capital;
- difficulties in integrating our operations as a result of any significant acquisitions, including the recent acquisition of Great Western Petroleum, LLC ("Great Western"), or acreage exchanges;
- adverse changes to our future cash flows, liquidity and financial condition;
- changes in, and interpretations and enforcement of, environmental and other laws and other political and regulatory developments, including in particular additional permit scrutiny in Colorado;
- the impact of public health crises, including the coronavirus 2019 ("COVID-19") pandemic, its effects on commodity prices, downstream capacity, employee health and safety, business continuity and regulatory matters;
- declines in the value of our crude oil, natural gas and natural gas liquids ("NGLs") properties resulting in impairments;
- changes in, and inaccuracy of, reserve estimates and expected production and decline rates;
- timing and extent of our success in discovering, acquiring, developing and producing reserves;
- reductions in the borrowing base under our revolving credit facility;

- availability and cost of capital;
- risks inherent in the drilling and operation of crude oil and natural gas wells;
- ability to add to our gross operated inventory through wellbore spacing and untested zones;
- timing and cost of wells and facilities;
- availability, cost, and timing of sufficient pipeline, gathering and transportation facilities and related infrastructure;
- limitations in the availability of supplies, materials, contractors and services that may delay the drilling or completion of our wells;
- potential losses of acreage or other impacts due to lease expirations, other title defects, or otherwise;
- risks inherent in marketing our crude oil, natural gas and NGLs;
- effect of crude oil and natural gas derivative activities;
- 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;
- impact to our operations, personnel retention, strategy, stock price and expenses caused by the actions of activist shareholders;
- uncertainties associated with future dividends to our shareholders or share buybacks;
- timing and amounts for cash federal and state income taxes;
- our ability to retain or attract senior management and key technical employees;
- an unanticipated assumption of liabilities or other problems with business acquisitions;
- cybersecurity disruptions to our operations from breaches of our information technology systems, or from breaches of third party systems;
- physical, financial and transition risks relating to climate change;
- changes in general economic, business or industry conditions, including changes in interest rates and inflation rates and concerns regarding national or global recessionary conditions;
- our ability to achieve our emissions reductions, flaring and other environmental, social and governance goals;
- the impact of the loss of a single customer or any purchaser of our products; and
- success of strategic plans, expectations and objectives for our future operations.

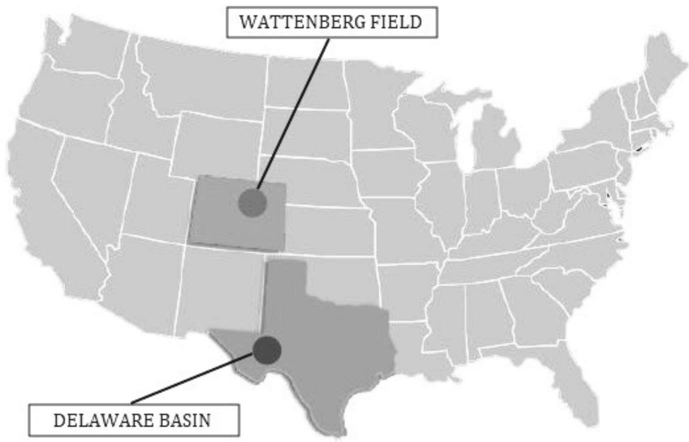
Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under Item 1A, *Risk Factors*, made in this report and our other filings with the U.S. Securities and Exchange Commission ("SEC") for further information on risks and uncertainties that 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, 2022:



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

	Year Ended/As of December 31, 2022	Year Ended/As of December 31, 2021	Percent Change 2022-2021
	(production and reserves in MMBoe, dollars in millions)		
Wells:			
Gross productive wells	4,098	3,471	18 %
Net productive wells	3,152	2,675	18 %
Horizontal percentage	74 %	66 %	12 %
Gross operated wells turned-in-line	183	167	10 %
Net operated wells turned-in-line	169	160	6 %
Production:			
Wattenberg Field	74.0	61.9	20 %
Delaware Basin	11.0	9.4	17 %
Total	85.0	71.3	19 %
Reserves:			
Proved reserves	1,100	814	35 %
Proved developed reserves percentage	47 %	49 %	(4)%
Standardized measure	$ 14,987	$ 7,908	90 %
PV-10 [(1)]	$ 19,053	$ 9,709	96 %
Available liquidity [(2)]	1,116	1,514	(26)%
Leverage ratio	0.5	0.6	(17)%

(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.

(2) Calculated as cash and cash equivalents plus availability under our credit facility, net of outstanding letters of credit, as of December 31.

Major Developments in 2022

Great Western Acquisition. On May 6, 2022, we completed the acquisition of Great Western for approximately $1.4 billion, inclusive of Great Western's net debt (the "Great Western Acquisition"). Great Western is an independent oil and gas company focused on the exploration, production and development of crude oil and natural gas in Colorado. The consideration paid was $542.5 million in cash and approximately 4.0 million shares of our common stock, valued at $293.3 million on the acquisition date, and payments totaling $597.0 million for termination of Great Western's debt. As a result of the Great Western Acquisition, we acquired approximately 54,000 net acres in the core Wattenberg Field and production of approximately 50,000 Boe per day. We financed the cash portion of the purchase price of Great Western Acquisition and the settlement of Great Western's debt through borrowings under our credit facility. We repaid the majority of our borrowings under our credit facility resulting from the Great Western Acquisition through cash flows from operating activities generated during 2022. As of December 31, 2022, we have a remaining balance on our credit facility of $370 million.

Capital Returns. In February 2022, our board of directors approved a new stock repurchase program that reset the total repurchase value to $1.25 billion and an increase in our quarterly base dividend from $0.12 per share to $0.25 per share. After the completion of Great Western Acquisition, in May 2022, our board of directors approved an additional increase in our quarterly base dividend from $0.25 per share to $0.35 per share. We also repurchased 12 million shares, or about 12 percent of our weighted average common stock outstanding, in 2022. Overall in 2022, we returned over 68 percent of our post base dividend adjusted free cash flows, a non-U.S. GAAP financial measure, through a combination of stock repurchases and quarterly and special dividends to shareholders.

Successful Approvals and Significant Progress of Wattenberg Permits. In June 2022, the Colorado Oil and Gas Conservation Commission ("COGCC") granted PDC unanimous approval for a 69-well Oil and Gas Development Plan ("OGDP") and a 30-well OGDP, our second and third approvals under the new permitting process. Additionally, in December 2022, the COGCC unanimously approved our first Comprehensive Area Plan ("CAP"), filed in December 2021, which encompasses approximately 450 wells in Weld County, Colorado. Following the approval of the CAP, we will submit individual OGDP packages for each of the locations within the CAP. The CAP, along with our prior OGDPs, represent the majority of our projected Wattenberg Field turn-in-line activity into 2028 based on our current pace and drilling plan in 2023.

Meaningful Milestone in Environment, Social and Governance ("ESG"). In May 2022, our board of directors approved quantitative metrics for greenhouse gas ("GHG") intensity and methane emissions reductions for our 2022 short-term incentive program, including 15% GHG and 30% methane emissions reduction targets from 2021 to 2022. In total, over 25% of our short-term incentive program is tied to ESG, environmental, health and safety initiatives. Further, in September 2022, we issued our first climate-related annual sustainability report aligned with the Taskforce on Climate-Related Financial Disclosures ("TCFD").

Our Business Strategies

Our long-term business strategy focuses on creating shareholder value by:

- Delivering attractive returns from our crude oil and natural gas properties with a keen focus on environmentally responsible and sustainable operations;
- Maintaining financial strength;
- Generating sustainable adjusted free cash flows, a non-U.S. GAAP financial measure;
- Returning capital to shareholders; and
- Driving continued improvement in our health, safety, and ESG programs.

Our Competitive Strengths

The following key attributes create long-term shareholder value:

- ***Strong financial position and sustainable capital return program.*** We are focused on generating multi-year sustainable cash flows from operations in excess of our capital investments and maintaining a disciplined financial strategy that focuses on strong liquidity, a low leverage ratio and an active commodity derivative program to help mitigate a portion of the risk associated with commodity price fluctuations. We are committed to returning capital to our shareholders in a variety of commodity price environments. We are dedicated to a premier return of capital program with a quarterly base dividend and a return of approximately 60 percent or more of our post base dividend adjusted free cash flows, a non-U.S. GAAP financial measure, through stock repurchases and special dividends, as needed.
- ***Project inventory in 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 northeast 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.
- ***Efficiency through technology and synergies from trades and accretive acquisitions.*** Technological innovation has led to continued improvement in our drilling and completion times and is helping us achieve our emission reduction goals. We are continuously investing in new technology to improve the efficiency and reduce the cost of our horizontal drilling and completion operations. Acreage consolidation made through trades or acquisitions in our operating areas

increases our ability to drill longer length lateral wells which allows us to develop our properties with a smaller number of wells.

- ***Committed to meaningful and measurable ESG strategy.*** We are committed to being a cleaner, safer and more socially responsible company.
    - ***Environment.*** We are committed to and are making meaningful progress on the following goals:
        - Reduce GHG intensity by 60% from 2020 levels by 2025 and 74% by 2030
        - Reduce methane intensity by 50% from 2020 levels by 2025 and 70% by 2030
        - Eliminate routine flaring, as defined by the World Bank, by 2025
    - ***Social.*** We value our employees' contributions and we focus on attracting and retaining a more diverse workforce. We strive to establish effective environmental, health and safety programs that promote safe practices for our employees and contractors.
    - ***Governance.*** We continue to commit to governance best practices and accountability to shareholders as we see this as a critical factor to our long-term success.

Operating Areas

Wattenberg Field. In the Wattenberg Field, we have identified a gross operated inventory of approximately 2,100 horizontal locations that we expect to generate acceptable rates of return based on forward strip pricing, with an average lateral length of approximately 10,000 feet. Our inventory consists of approximately 200 gross operated DUCs, 915 approved permits or CAP locations, reflecting approximately five years of turn-in-line activity based on our current drilling plan, and 985 unpermitted locations. The 2022 CAP, along with our prior OGDPs, represent the majority of our projected Wattenberg Field turn-in-line activity into 2028 based on our current pace and drilling plan in 2023.

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, reaching the Niobrara and Codell plays. 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, with a relaxed spacing program of approximately eight wells per undeveloped section equivalent and new operational techniques, we have a gross operated economic inventory of approximately 60 horizontal locations, representing approximately three years of inventory based on our current drilling plan. Our inventory consists of 12 gross operated DUCs that we expect to generate acceptable rates of return based on forward strip pricing, targeting the Wolfcamp A and B zones. The average lateral length of these locations is approximately 11,100 feet. Wells in the Delaware Basin typically have productive stacked-pay horizons at depths of approximately 9,000 to 11,500 feet below the surface, reaching the Wolfcamp zones. In 2023, our drilling program will include some untested target zones that may be subject to a higher degree of uncertainty. If successful, we anticipate the program will allow us to increase our field inventory. 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 or to increase our ownership in our operated wells.

We currently operate approximately 79 percent of 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 locations on those leases.

Oil and Gas Production and Operations

Proved Oil and Gas Reserves

The following table presents our proved reserve estimates as of the dates indicated:

	December 31,		
	2022	2021	2020
Proved reserves			
Crude oil and condensate *(MMBbls)*	270	214	212
Natural gas *(Bcf)*	2,893	2,160	1,901
NGLs *(MMBbls)*	348	240	203
Total proved reserves *(MMBoe)*	1,100	814	731
Proved developed reserves *(MMBoe)*	518	399	322
Standardized measure *(in millions)*	$ 14,987	$ 7,908	$ 3,282
Estimated undiscounted future net cash flows *(in millions)* (1)	$ 26,916	$ 13,872	$ 5,633
PV-10 (*in millions)* (2)	$ 19,053	$ 9,709	$ 3,455

(1) Amount represents aggregate undiscounted future net cash flows, before income taxes, of approximately $34.0 billion, $17.0 billion and $5.9 billion as of December 31, 2022, 2021 and 2020, respectively, less an internally-estimated undiscounted future income tax expense of approximately $7.1 billion, $3.1 billion and $0.3 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, 2022 as compared to December 31, 2021 were primarily due to (i) the reserves acquired in the Great Western Acquisition, (ii) positive revisions resulting from our development activities and (iii) upward revisions as a result of significant improvements in commodity prices during 2022, resulting in better economics and therefore increased quantities of reserves.

The additions to our proved reserves at December 31, 2021 compared to December 31, 2020 were primarily due to positive revisions resulting from our development activities and significant improvements in commodity prices during 2021, resulting in better economics.

The additions to our proved reserves at December 31, 2020 as compared to December 31, 2019 were primarily due to the reserves acquired from our merger with SRC Energy, Inc. ("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, 2022:

Operating Region/Area	Crude Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Crude Oil Equivalent (MMBoe)	Percent
Proved developed					
Wattenberg Field	102	1,209	154	457	41 %
Delaware Basin	22	146	15	61	6 %
Total proved developed	124	1,355	169	518	47 %
Proved undeveloped					
Wattenberg Field	135	1,458	171	549	50 %
Delaware Basin	11	80	8	33	3 %
Total proved undeveloped	146	1,538	179	582	53 %
Total proved reserves					
Wattenberg Field	237	2,667	325	1,006	91 %
Delaware Basin	33	226	23	94	9 %
Total proved reserves	270	2,893	348	1,100	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)
2022	$ 93.67	$ 6.36	$ 93.67
2021	66.56	3.60	66.56
2020	39.57	1.99	39.57

(1) Our benchmark indexes 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 Mcf)	NGLs (per Bbl)
2022	$ 94.23	$ 4.82	$ 31.60
2021	65.37	2.85	24.96
2020	37.52	1.26	10.55

(1) These prices are based on 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, 2022 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 2022 NYMEX price for crude oil used in estimating our reported proved reserves with $75 per Bbl and $50 per Bbl as shown on the table below, and leaving all other parameters unchanged, including natural gas pricing, NGL pricing and future costs, 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, 2022 Estimated Reserves	PV-10 (in Millions)	PV-10 % Change from December 31, 2022 Estimated Reserves
2022 SEC Reserve Report (1)	$ 93.67	$ 6.36	1,099,766	—	$ 19,053.0	—
Alternate Price Scenario 1	$ 75.00	$ 6.36	1,092,010	(1)%	$ 15,270.0	(20)%
Alternate Price Scenario 2	$ 50.00	$ 6.36	1,075,461	(2)%	$ 10,185.0	(47)%

(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.

Reserves 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, 2022 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, 2022.

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 the respective 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 Degree in Petroleum Engineering from the Colorado School of Mines and a Bachelors Degree in Geology from the University of Colorado and has over 22 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, 2022 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, 2022, 2021 and 2020 is 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, 2022:

	Crude Oil		Natural Gas		Total	
Operating Region/Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Wattenberg Field	3,013	2,224	930	801	3,943	3,025
Delaware Basin	53	37	102	90	155	127
Total productive wells	3,066	2,261	1,032	891	4,098	3,152

Productive wells consist of producing wells and wells capable of production, including crude oil wells awaiting pipeline connections to commence deliveries, natural gas wells awaiting connection to production facilities and shut-in wells.

Developed and Undeveloped Acreage

The following table presents our developed and undeveloped lease acreage as of December 31, 2022:

	Developed		Undeveloped		Total	
Operating Region/Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Wattenberg Field	222,037	201,827	80,950	72,741	302,987	274,568
Delaware Basin	27,636	24,703	959	906	28,595	25,609
Total acreage	249,673	226,530	81,909	73,647	331,582	300,177

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 the majority of this acreage has significant remaining development potential in one or more intervals with horizontal wells. Undeveloped acreage represents 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. However, substantially all of our undeveloped acreage in the Wattenberg Field and Delaware Basin is related to leaseholds that are held by production and therefore are not at risk of expiration or delay rental payments.

Our Wattenberg Field and Delaware Basin leaseholds at risk to expire in 2023 through 2025 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.

	Operated Development and Exploratory Well Drilling Activity As of and For the Year Ended December 31,					
	2022		2021		2020	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Wattenberg Field	164	150	149	143	124	117
Delaware Basin	19	19	16	16	13	13
Total development wells	183	169	165	159	137	130
In-Process Development Wells						
Wattenberg Field	200	185	143	133	214	202
Delaware Basin	12	12	21	21	18	17
Total in-process wells	212	197	164	154	232	219
Developmental Wells - Dry Hole						
Wattenberg Field	1	1	—	—	—	—
Delaware Basin	2	2	—	—	—	—
Total developmental wells - dry hole	3	3	—	—	—	—
Exploratory Wells - Delaware Basin						
Productive	—	—	2	2	2	2
Dry Hole	1	1	—	—	—	—
In-Process	—	—	—	—	2	2

There were no exploratory drilling activities in the Wattenberg Field during 2022, 2021 and 2020.

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, 2022, 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. In January 2022, we entered into a long-term lease agreement for office space located in Denver, Colorado.

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, crude 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 one customer that represented 10 percent or more of our 2022 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, including severe weather conditions, 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 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 may also exist in Colorado, where the COGCC has recently imposed minimum requirements for ownership and consent in order to obtain a force pooling order. 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 crude oil, natural gas and NGLs through pipelines owned by other entities and sell these commodities to other entities that also utilize common carrier pipeline facilities. The Federal Energy Regulatory Commission regulates (i) the interstate transmission and storage of gas under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and (ii) the interstate movement of liquids, including crude and NGLs, under the Interstate Commerce Act as it existed on October 1, 1977, as well as rules and regulations promulgated under such statutes and other laws. The availability, terms and cost of transportation can be impacted by these regulations and may affect the amounts we receive for our commodities.

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. Pursuant to these statutes, the U.S. Environmental Protection Agency ("EPA") and various state agencies have adopted requirements that require approved disposal methods for certain hazardous and non-hazardous wastes. From time to time, EPA considers adoption of stricter disposal standards under RCRA. If new standards are adopted, it could increase maintenance and capital expenditures and operating expenses. 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.

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") authorizes governmental authorities 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. Following the acquisition of Great Western in 2022, however, we also have significant acreage and operations in Adams County, a more urban setting that poses more regulatory challenges. 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 requirements prohibit the siting of locations within 2,000 feet of a school facility or child-care center. A similar 2,000-foot setback requirement applies to residential and high occupancy building units, but there are "off ramps" allowing oil and gas operators to site their drill pads as close as 500 feet from building units in certain circumstances.

In July 2020, Governor Polis authored an op-ed stating that both industry and mainstream environmental groups communicated a willingness to work together to prevent ballot initiatives in 2022. 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. There were no oil and gas ballot initiatives in 2022 that would have imposed additional regulations on the oil and gas industry.

It is nevertheless possible that future ballot initiatives will be proposed that could limit the areas of the state in which drilling would be permitted to occur or otherwise impose increased regulations on our industry. 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

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 subject to an appeal.

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 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 Clean Air Act ("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. On August 16, 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law. The IRA imposes a fee of up to $1,500 per metric ton of methane emitted above specified thresholds from onshore petroleum and natural gas production facilities, natural gas processing facilities, natural gas transmission and compression facilities, and onshore petroleum and natural gas gathering and boosting facilities, among other facilities. The fees will apply to methane emissions after January 1, 2024. We do not anticipate that such fees will have material effect on our financial condition or results of operations. Congress may adopt additional significant legislation in the future to reduce emissions of GHGs.

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 rules regulating methane emissions from the oil and gas sector.

In response to Colorado's established statewide Climate Action Plan to Reduce Pollution, HB 19-1261, in September 2020, the state released a public comment draft of its Greenhouse Gas Pollution Reduction Roadmap, which detailed early action steps the state can take toward meeting the near-term goals of reducing GHG pollution by 26% by 2025 and 50% by 2030 from 2005 levels. In October 2020, the Air Quality Control Commission ("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, as well as to address other air quality and environmental justice issues, the AQCC held a hearing in December 2021 and voted to adopt additional requirements and emission limitations applicable to oil and gas facilities in Colorado. The adopted regulatory requirements include, for example, more frequent fugitive emissions monitoring, a statewide GHG intensity program, emission limitations for well liquids unloading, and comprehensive testing of emission control devices. Colorado is expected to engage in additional rulemakings over the next several years related to GHG reductions in the oil and gas industry.

In April 2021, President Biden announced that the United States would aim to cut its greenhouse gas emissions 50 percent to 52 percent below 2005 levels by 2030. This commitment will be part of the United States' "nationally determined contribution," or NDC, to the Paris Climate Agreement. The NDC will commit the United States to a voluntary GHG emission reduction target and outline domestic climate mitigation measures to achieve that target.

Regulation of methane and other GHG emissions associated with oil and natural gas production could impose significant requirements and costs on our operations. See our GHG emission reduction goals included in *Items 1. and 2. Business and Properties* included elsewhere in this report.

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.

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 November 2021, EPA published a proposed rule that would update and expand existing requirements for the oil and gas industry, as well as creating significant new requirements and standards for new, modified, and existing oil and gas facilities. The proposed new requirements would include, for example, new standards and emission limitations applicable to storage vessels, well liquids unloading, pneumatic controllers, and flaring of natural gas at both new and existing facilities. In November 2022, the EPA published a supplemental proposal to update, strengthen, and expand the standards proposed in November 2021. The proposed rules for new and modified facilities are estimated to be finalized by the end of 2023, while any standards finalized for existing facilities will require further state rulemaking actions over the next several years before they become applicable and effective.

In November 2022, the BLM published a proposed rule that would regulate venting, flaring and leaks during oil and gas production activities on federal and Indian leases. If finalized as proposed, the rule would limit gas that may be flared royalty-free during well completions, production testing, and emergencies; establish a monthly volume limit on royalty-free flaring due to pipeline capacity constraints, midstream processing failures, or other similar events; require vapor recovery systems on oil tanks; require operators to maintain leak detection and repair ("LDAR") programs; prohibit the use of certain natural-gas-activated pneumatic controllers and pneumatic diaphragm pumps; and require operators to submit waste minimization plans with applications for permit to drill, among other requirements.

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. The Denver Metro/North Front Range NAA was further "bumped-up" to "severe" status in 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.

In addition, SB 19-181 requires, among other things, that the 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. Since December 2019, the AQCC completed several rulemakings as a result of SB 19-181 and other state legislation, adopting significant additional and new emission control and monitoring 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 is expected to conduct additional rulemakings over the next several years that may result in additional regulatory requirements for oil and gas facilities.

Scrutiny of oil and gas operations and the rules affecting them have increased in Texas 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"). For years, both via administrative rulemakings and actions and judicial interpretation and intervention, the definition of "WOTUS" and how it has been applied has been in flux. In 2019 and 2020, the EPA and the Army Corps of Engineers ("USACE") issued a final rule to repeal previous regulations and promulgated a new replacement rule (the "Navigable Waters Protection Rule"). The Navigable Waters Protection Rule was vacated by two separate federal district courts in late 2021. In November 2021, EPA and USACE issued a pre-publication version of another rule largely reinstating the previous 1986 WOTUS rule and guidance "with certain amendments" to reflect "consideration of the agencies' statutory authority under the CWA and relevant Supreme Court decisions" (the "2021 Proposed Rule"). The 2021 Proposed Rule was published in the Federal Register in December 2021. In addition to the 2021 Proposed Rule, in September 2022, the EPA and USACE sent the draft final rule to implement the 2021 Proposed Rule to the Office of Management and Budget for interagency review, but no final rule has yet been issued by the agencies. It is unknown at this time when the 2021 Proposed Rule will take effect; when the next forthcoming proposed amendments are expected; and/or whether either new rule will be challenged and withstand any challenges in federal court. Finally, in January 2022, the United States Supreme Court granted review of *Sackett vs. EPA*, which involves issues related to CWA scope and jurisdiction and could impact the current rulemaking process. The Supreme Court heard oral argument in *Sackett* in October 2022, and a decision is expected in 2023. Although the outcome of the 2021 Proposed Rule and additional forthcoming amendments to the WOTUS regulations is unknown, the regulations under the Biden Administration are undoubtedly more stringent in terms of the scope of WOTUS, which could ultimately change the scope of the CWA's jurisdiction and 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. As noted above, however, things are constantly in flux and the fate of the definition of "WOTUS" under the CWA and how that ultimately will be applied by the Agencies is yet to be seen.

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 are located in areas that are or may be designated as habitats for endangered or threatened species or that may attract migratory birds, bald eagles, golden eagles or other wildlife. The designation of these habitats could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Other

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") establishes requirements for preparation and EPA approval of Facility Response Plans and 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 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.

In June 2020, the COGCC amended its regulations regarding wellbore integrity. The amended rules impose additional requirements regarding the permitting, construction, operation, and closure of wells. Furthermore, in March 2022, the COGCC adopted new financial assurance rules pursuant to SB 19-181 that require every operator to provide assurance that it is financially capable of fulfilling the obligations imposed by the COGCC's rules. In particular, the rules increase the financial assurance required for inactive or low producing wells and require that operators maintain single well financial assurance to cover the full cost of plugging, abandoning, and reclaiming wells, with a focus on inactive and transferred wells. The new financial assurance rules became effective on April 30, 2022. PDC will obtain a $40 million bond in 2023 in order to comply with the rules.

In addition, on May 10, 2022, the Colorado Legislature adopted SB 22-198, the "Orphaned Oil and Gas Well Enterprise" bill, which requires each oil and gas operator in Colorado to pay a mitigation fee to the "enterprise" for each well that has been spud but not yet plugged and abandoned. The COGCC submitted a notice of rulemaking on May 18, 2022 to implement SB 22-198 by amending the COGCC's annual registration fee rules to now require that an operator's annual registration fee be paid to the enterprise as a "mitigation fee." In addition, the newly established "Enterprise Board" now has the authority to adjust the dollar amount of the mitigation fee. The amendments became effective on June 30, 2022, and may increase the registration fees required for current and future oil and gas wells in Colorado.

Finally, on August 30, 2022, environmental groups filed a petition for rulemaking with the COGCC, petitioning the COGCC to adopt new rules to evaluate and address the cumulative air impacts of oil and gas development in Colorado. The petition proposes to address the cumulative air impacts of oil and gas development by effectively prohibiting any oil and gas project located in an area where the air quality exceeds, or may exceed, applicable air quality standards. In effect, the petition for rulemaking calls for a blanket prohibition on oil and gas development in much of Colorado. The COGCC denied the petition; however, the COGCC initiated a cumulative impacts stakeholder process to determine how best to address cumulative impacts going forward, which may include additional regulations.

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 Management

We believe that our employees play a critical role in the achievement of our short-term and long-term business goals. Consequently, we are committed to attracting, retaining and developing highly motivated and qualified employees who share our core values.

Employee Engagement and Retention

We recognize and support the growth of our employees by offering internal and external development programs. We offer on-demand developmental training content and provide educational benefits and developmental stipends to support employees' continued professional development. We utilize an online training platform to allocate and track certain employee trainings. In 2022, our employees completed approximately 8,900 hours in aggregate within our platform alone on a variety of training topics, including safety, to strengthen their skills and advance their careers. We also conduct an annual advanced leadership program for targeted employees at different levels of the Company to promote cross departmental collaboration and further develop leadership skills through simulations and actual business projects.

As of December 31, 2022, we had 616 full-time employees, 301 of whom are employed in field operations. We also engage independent contractors and service providers on an as needed basis to support our business operations. During 2022, our voluntary turnover was around 10 percent. Our employees are not covered by collective bargaining agreements.

Employee Compensation and Benefits

Our compensation program is designed to provide competitive salaries and comprehensive 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 seek fairness in total compensation and benefits with reference to external benchmarking against our peers in the industry. All full-time employees are eligible for health insurance, paid and unpaid leave, retirement benefits (including an employer match up to 10% of wages), life and disability/accident coverage, well-being and other benefits. We offer stock awards that vest over multiple years to support retention, reward performance, and align the interests of our employees with stockholders through encouragement of stock ownership. We believe that our compensation and benefits package is a strong retention tool and promotes physical, mental, financial and social health within our workforce.

Community Involvement

We are dedicated to community well-being and success and we seek to be a good partner in the communities in areas in which we operate. All of our employees are encouraged to participate in community outreach events and partnerships to support the communities where we operate, and we support our employees' ongoing efforts to enrich the communities where they live and work. In 2022, our employees recorded approximately 7,500 volunteer hours in their communities.

Diversity, Equity and Inclusion ("DEI")

We believe diversity, equity and inclusion provides a business with growth and increased innovation and ultimately leads to a successful workforce. We are committed to providing equal opportunity in all aspects of employment and to hiring, evaluating and promoting our employees based on skills and performance. We have an employee-led DEI project team working with a third party specialist to develop a DEI charter for incorporation into our overall strategy.

Approximately 26%, or 163, of our employees are women and 23% or 143, are members of a minority group, as defined by the U.S. Equal Employment Opportunity Commission, as of December 31, 2022. As of the same date, 28%, or 38, of our executives are women and 18%, or 25, are members of a minority group. Since the beginning of 2021, we have expanded the diversity of our board of directors by adding three new diverse members with a unique set of backgrounds and experiences.

Health and 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 in an effort to ensure we are meeting or, where possible, exceeding new requirements and adopting new technologies to responsibly improve our operations. Additionally, all PDC field employees receive safety training upon hire and attend frequent meetings and refreshers to reinforce safety as a core value and our most important strategic priority. As a result of our commitment to health and safety, we have gone over four years without an employee lost time incident in either basin.

Our continual commitment to safety has resulted in improved safety records. Since the time the 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 represents 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 as part of our quantitative performance metrics under our STI program. For 2022, our TRIR was below the most recent Bureau of Labor Statistics average for our industry.

Refer to our Corporate Social Responsibility Report published on our website for performance highlights regarding various human capital measures and additional sustainability information. Information contained in our Corporate Social Responsibility Report is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

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.

Adverse changes in general economic conditions could have a material adverse effect on our business, results of operations and financial condition.

Current or future economic uncertainties or downturns, including those caused by the COVID-19 pandemic, could adversely affect our business and operating results. Adverse macroeconomic conditions may result from, among other things, changes in gross domestic product growth, financial and credit market fluctuations, rising inflation, recessions, political deadlocks, natural catastrophes, pandemics, military conflicts (such as the Russian invasion of Ukraine) or terrorist attacks, whether in the United States, Europe, the Asia Pacific region or elsewhere, and may result in adverse impacts on our business, including depressed crude oil, natural gas and NGL pricing, reductions in force, and reduced capital expenditures.

For example, during 2021 and 2022, the United States experienced inflation rates of approximately 7% and 6.5%, respectfully, according to data from the U.S. Bureau of Labor Statistics, which were significant increases relative to prior years. If inflation rates remain elevated or increase further, our expenses and operating costs are likely to increase as well. Inflation may also result in higher interest rates and otherwise adversely impact the macroeconomic environment, which in turn could adversely impact commodity pricing. Additionally, in recent periods the U.S. has experienced a labor shortage, which has contributed to an environment of escalating wages and salaries, which may also adversely affect our operating costs and contribute to general inflationary pressures.

We cannot predict the timing, strength or duration of any economic slowdown, instability or recovery, generally or within any particular industry. If economic conditions in the general economy or industries in which we operate do not improve, or worsen from present levels, our business, operating results, financial condition and cash flows could be adversely affected.

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.

Many aspects of our business depend upon crude oil, natural gas and NGL prices, 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:

- changes in regional, national or global economic conditions and trends, including supply and demand;
- geopolitical factors and events that reduce or increase production from 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 Russia’s invasion of Ukraine; and
- regulatory changes.

The price of oil has historically been volatile due to a variety of factors including global supply and economic conditions. In the past two years, oil prices have ranged from highs over $130 per barrel to lows of approximately $45 per barrel. 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 result in reduced cash flow from operations. Reduced cash flow would limit our ability to make the capital expenditures necessary to replace our reserves and production.

In addition to factors generally affecting the price of crude oil, natural gas and NGLs, the prices we receive for our production are affected by factors specific to us and to the local markets where production occurs. The prices we receive for our production vary from 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 markets and other forces, including local or regional supply and demand factors; terms of our sales contracts; investment decisions made by providers of midstream facilities and services, refineries and other industry participants; and the overall regulatory and economic climate. Widening differentials may materially and adversely impact our business.

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. 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 ("CD") pursuant to which we paid a fine and agreed to implement certain operational changes. In addition, as a result of the acquisition of SRC Energy, Inc. ("SRC"), and Great Western Petroleum, LLC ("GW"), we became subject to SRC's 2018 Compliance Order on Consent ("SRC COC") and GW's 2018 Compliance Order on Consent ("GW COC"), each of which involved issues similar to those addressed in the CD. As of December 31, 2022, each of these matters have been resolved. The CD was terminated on December 15, 2022; the SRC COC was terminated on February 28, 2022; and the GW COC was terminated on November 7, 2022. We may, however, be subject to similar lawsuits and orders in the future.

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*, there is continued ambiguity around COGCC permitting rules as implementation continues. In 2023, we anticipate continued rulemakings and guidance from the COGCC Commissioners and staff. We expect to participate in the stakeholder process to create rules and guidance around high-priority habitat, workers safety and cumulative impacts. We cannot predict the ultimate impact of these requirements on our inventory and operations.
- 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. 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.
- 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.
- Corporate governance, public disclosure and compliance practices continue to evolve based upon continuing legislative action, SEC rulemaking and policy positions taken by large institutional stockholders and proxy

advisors. As a result, the number of rules, regulations and standards applicable to us may become more burdensome to comply with, could increase scrutiny of our practices and policies by these or other groups and increase our legal and financial compliance costs and the amount of time management must devote to governance and compliance activities. For example, the SEC has recently proposed rules requiring that issuers provide significantly increased disclosures concerning cybersecurity matters, insider trading policies and procedures and the impact of climate changes on their business.

Increasing scrutiny, changing expectations from stakeholders and proposed reporting requirements by regulatory bodies with respect to climate-related risk and ESG may impose additional costs on us or expose us to new or additional risks.

Publicly traded companies, both in the oil and natural gas industry and otherwise, are facing increased scrutiny from stakeholders regarding climate changes and ESG matters. Attention to these issues has come from stakeholders including the SEC, local governments and institutional investors, and these stakeholders have and may in the future seek certain outcomes or results on issues they perceive to be material. For example, the SEC has recently proposed rules to enhance and standardize climate-related disclosures for investors. This increased scrutiny could result in reduced access to capital, shareholder proposals and other adverse effects. Companies that fail to adapt or comply with evolving stakeholder expectations, or are perceived as failing to respond appropriately, could suffer from reputational damage and the business, financial condition, and/or stock price of such a company could be materially and adversely impacted.

Many scientists have shown that increasing concentrations of carbon dioxide, methane and other GHGs in the Earth's atmosphere are changing global climate patterns. The following is a summary of potential climate-related risks that could adversely affect us:

Transition Risks. Transition risks are related to the transition to a lower-carbon economy and include the risk of reduced demand and lower prices for our production.

Policy and Legal Risks. Policy risks include those arising from the regulatory actions intended to discourage activities that contribute to the adverse effects of climate change or to promote adaptation to climate change. President Biden's administration has made addressing climate change a high priority, and this could lead to a more challenging regulatory environment. Examples of policy actions from federal, state or local governments that could increase the costs of our operations, reduce our future development or production or reduce demand for our oil and gas include the implementation of carbon-pricing mechanisms, regulations designed to shift energy use toward lower emission sources, regulations regarding energy and water use efficiency, regulations disallowing development or production activity on high ozone level days, and regulations intended to promote sustainable land use. Policy actions also may include restrictions or bans on oil and gas activities, which could lead to write-downs or impairments of our assets.

Legal risks include potential lawsuits based on alleged failures to mitigate impacts of climate change, failures to adapt to climate change and disclosure matters. For example, we may be subject to climate-related litigation such as "greenwashing" suits with respect to our operations, disclosures, or products. Although we are not a party to any such climate-related or "greenwashing" litigation currently, unfavorable rulings against us in any such case brought against us in the future could significantly impact our operations and could have an adverse impact on our financial condition.

Technology Risks. Technological improvements or innovations that support the transition to a lower-carbon, more energy efficient economic system may have a significant impact on us. The development and use of emerging technologies in renewable energy, battery storage, and energy efficiency may reduce demand for oil and gas, resulting in lower prices and revenues, and higher costs. In addition, many automobile manufacturers have announced plans to shift production from internal combustion engine vehicles to electric powered vehicles, and some states and foreign countries have announced bans on sales of internal combustion engine vehicles beginning as early as 2025, which could reduce demand for oil.

Market Risks. Markets could be affected by climate change through shifts in supply and demand for certain commodities, especially carbon-intensive commodities such as oil and gas and other products dependent on oil and gas. Lower demand for our oil and gas production could result in lower prices and lower revenues. Market risk also may take the form of limited access to capital as investors shift investments to less carbon-intensive industries and alternative energy industries. In addition, certain investment advisers, banks, and sovereign wealth, pension, and endowment funds have in recent years been promoting divestment of investments in fossil fuel companies and pressuring lenders to limit funding to companies engaged in the extraction, production, and sale of oil and gas. We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, or at all.

Reputational Risk. Climate change is a potential source of reputational risk, which is tied to changing customer or community perceptions of an organization's contribution to, or detraction from, the transition to a lower-carbon economy.

Physical Risks. Potential physical risks resulting from climate change may be event driven (including increased severity of extreme weather events, such as hurricanes, droughts, or floods) or may be driven by longer-term shifts in climate patterns that may cause sea levels to rise or chronic heat waves. Potential physical risks may cause direct damage to assets and indirect impacts, such as supply chain disruption, and also could include changes in water availability, sourcing, and quality, which could impact drilling and completion operations. These physical risks could cause increased costs, production disruptions, and lower revenues and could substantially increase the cost or limit the availability of insurance.

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, the demand for, and cost of, drilling rigs, equipment, supplies, chemicals, personnel and oilfield services often increase as a result of numerous factors including increases in exploration and production activity, supply chain problems, and labor shortages. 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 past three years are located in the Wattenberg Field. As a result, the transactions 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 which we do not control. If these facilities are unavailable, or if we are unable to access these facilities on commercially reasonable terms, our operations could be interrupted, negatively affecting our results of operations.

Our ability to market our production depends in substantial part on the availability, proximity and capacity of in-field gathering systems, compression and processing facilities, and transportation pipelines, all of which are 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.

Availability or capacity issues can be a result of increased commodity prices that incentivize increased drilling and completion activities and increase commodity supplies, potentially constraining transportation capacity and subsequently lowering production volumes and realized prices. The increased commodity supplies can sometimes be more heavily weighted toward one commodity versus another. For instance, increased crude oil and natural gas prices in the first half of 2022 have incentivized producers in the Permian Basin to increase the level of drilling and completion activities. The potential increase in production levels has led to high utilization of the existing pipeline capacity out of the region. Until new pipeline expansions are placed in service, the transportation constraints in the Permian Basin may lead to lower realized natural gas prices.

These issues can also result from depressed commodity prices that ultimately reduce investment in new midstream facilities. Additionally, protests over construction of new pipelines and facilities, new or amended government regulations curtailing drilling activities in Colorado which could discourage investment in midstream facilities, extreme weather, fire, or other reasons could also negatively affect our production volumes and realized prices.

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 shortfalls, deficiency, or similar fees.

Our undeveloped acreage must be drilled before lease expiration, and production must thereafter be maintained under applicable lease terms to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells and thereafter maintain production under applicable lease terms 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 and thereafter maintained under applicable lease terms within the spacing or pooled 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 or our ongoing production 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 or production declines or is otherwise shut-in. Our ability to drill, develop, and maintain production under applicable lease terms from the locations necessary to maintain our leases depends on a number of factors, 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, and regulatory approvals, all of which are subject to risks and uncertainties.

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

Prior to acquiring oil and gas leases or interests, we engage oil and gas lease brokers or landmen (rather than title attorneys) to perform record title examinations. The existence of a material title deficiency can decrease a lease's value 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 and produced 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 2022, a magnitude 5.4 earthquake occurred within the Delaware Basin. In response, the Texas Railroad Commission has taken actions to significantly reduce deep and shallow salt water disposal injection volumes in certain areas. This increased scrutiny applies to our Colorado operations as well, though to a lesser extent.

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 in 2020, to write down assets. Similarly, the significant decline in commodity pricing that occurred in 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 our 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 will materially affect the quantities and present value of our reserves.

The process of estimating 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. In determining the estimates of reserve and economic evaluations, management utilizes independent petroleum engineers. The reserve estimates are based on assumptions regarding commodity prices, production levels and operating and development costs that may prove to be incorrect. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be inaccurate and revisions in existing reserve estimates occur.

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.

You should not assume that the present value of the estimated future net cash flows from our proved reserves is 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 average of the previous 12-months' first day of the month prices and costs as of the date of the estimate. Actual future prices and costs may be materially different. Further, actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production and changes in governmental regulations or taxes. Significant variances could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K and cause potential impairment charges. Sensitivity of our proved reserves as of December 31, 2022, assuming specified decreases in crude oil prices, are disclosed in *Oil and Gas Production and Operations section in Item 1 and 2. Business and Properties, included elsewhere in this report.* 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. Conversely, a decrease in well density could result in fewer locations in an area but possibly increased production performance on a per-well basis. For example, after examining well performance and other factors, we determined in 2021 that our Delaware Basin position supported fewer wells per unit than previously assumed. Accordingly, our estimated well locations for our Delaware Basin position decreased from 135 to 65 in 2021.

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 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 that generally do not apply to our leases 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 continued a steady pace of development in the Wattenberg Field over the past several years, and while our business acquisitions have increased our inventory, continued development has reduced our inventory of drilling locations. We also 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 (as to acreage and/or depths) and our continued analysis of geologic challenges in certain areas. For example, as noted above, in 2021, we reduced our estimated number of locations in the Delaware Basin due to geological issues.

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 plugged and abandoned in accordance with applicable regulations. For example, in 2022, our drilling activity in the third Bone Spring formation resulted in an exploratory dry hole. This generally results in the loss of the entire cost of drilling and completion to that point. 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;
- inflation in exploration, drilling, completion and production costs;
- 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, loss of wells, pollution, environmental contamination 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. In addition, 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 which we have no effective 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 use 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.

Our customers, counterparties and lenders may be unable to satisfy their contractual or legal obligations.

We are exposed to certain risks associated with our customers, contractual counterparties and lenders. These risks include credit risks associated with (i) customers who purchase our oil, NGLs and natural gas production, (ii) the collection of receivables from our joint interest partners for their proportionate share of expenditures made on projects we operate, and (iii) counterparties to our derivative financial contracts. We are also subject to performance risks associated with the non-delivery, or delayed delivery, of contracted products or services, including the transportation and processing of our oil, NGLs and natural gas production and liquidity risk in the event one or more lenders under our existing credit facility are unable to perform their funding obligations. In the event a customer, contractual counterparty or lender fails to satisfy their obligations, our business, financial condition and results of operations could be materially and 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, 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. Additionally, larger competitors may have greater financial, technical and personnel resources that may provide technological advantages and may in the future allow them to implement new technologies before we can. 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.

Further, our operations require laborers, including contractors, skilled in multiple disciplines, such as heavy equipment operators, mechanics and engineers, among others. A shortage in skilled labor can increase the risk of safety issues, decrease our overall productivity and business results and increase the labor, health care and benefits costs we incur to attract and retain high quality employees with the right skill sets to meet our needs. For example, in 2022 we experienced an increase in contractor injuries at our worksites, many attributable to the labor conditions in the oilfield, including a greater number of short-service contractor employees.

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

Acquisitions of producing and undeveloped properties 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 typically 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 after the acquisition. 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.

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, in January 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 any such legal or other proceedings 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 *Item 3. Legal Proceedings* 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. Critical infrastructure targets, such as energy-related assets and transportation assets, may be at greater risk of future cyber-attacks than other targets. 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 various procedures, facilities, infrastructure and controls we utilize to monitor these threats and mitigate our exposure to such threats are costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. 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 and planned business transactions. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. To our knowledge, we have not suffered material losses related to cyber-attacks to date; however, there can be no assurance that we will not suffer material losses in the future either as a result of an interruption to or a breach of our systems or those of our third-party vendors and service providers. 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. Insurance may not provide adequate protection from these risks. 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.

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 increasing climate change awareness, 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. The number of lenders participating in our revolving credit facility decreased in connection with the amendment and restatement of the facility in 2021, and may decline further in the future. Our inability to obtain sufficient financing on acceptable terms would adversely affect our financial condition and profitability.

The cost of servicing, and risks related to refinancing, our debt could adversely affect our business. Those risks could increase if we incur more debt.

As of December 31, 2022, we had total long-term debt of $1.32 billion. Servicing our indebtedness and satisfying our other obligations will require a significant amount of cash, and 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.

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, selling assets, refinancing all or a portion of our existing debt or obtaining additional financing. We may not be able to complete any such steps on satisfactory terms. Any inability to generate sufficient cash flows to satisfy our debt obligations or contractual commitments, or to refinance our debt on commercially reasonable terms, could materially and adversely affect our financial condition and results of operations. In addition, our financing costs are affected by changing macroeconomic factors, including in particular interest rates. For example, under our revolving credit facility, one of the applicable interest rates on amounts borrowed at the end of 2021 was 0.1% and has since increased to 4.4% as of the end of 2022, resulting in higher costs on our outstanding debt.

Covenants in our debt agreements currently impose, and future financing agreements may impose, 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 certain liens;
- make specified types of investments;
- apply net proceeds from certain asset sales;
- engage in transactions with our affiliates;
- engage in sales and leaseback transactions;
- merge or consolidate; 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 current operating subsidiaries. The restrictions contained in our current or future debt agreements, including the possible addition of ESG-related metrics pursuant to our existing amended and restated credit agreement, may prevent us from taking actions that we believe would be in the best interest of our business, or may increase cost of borrowings in the future. In addition, our ability to comply with covenants and restrictions in our debt agreements 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 debt agreements. In the event of such a default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder, and under other agreements to which a cross-default or cross-acceleration provision applies, 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.

Our lenders have sole discretion to set our borrowing availability based on anticipated commodity prices and corporate outlook.

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 may 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.

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, 2022, we had hedged a total of 25.3 MMBbls crude oil for 2023 to 2025 and 214.8 BBtu of natural gas for 2023 to 2025. 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.

We may be unable to return capital to our stockholders, and there is no assurance we will pay any dividends on or repurchase shares of our common stock in the future or at levels anticipated by our stockholders.

Starting in 2022, we adopted a return of capital program with a quarterly base dividend and a return of approximately 60 percent or more of our post base dividend adjusted free cash flows, a non-U.S. GAAP financial measure, through stock repurchases and special dividends, as needed. Additionally, since the first quarter of 2022, our board of directors has approved the increases in quarterly base dividend from $0.12 per share to $0.40 per share. Our ability to pay cash dividends and to otherwise return capital to shareholders in the future depends on, among other things, our liquidity, financial condition, financial requirements, contractual restrictions, restrictions imposed by applicable law and other factors considered relevant by our board. Our board, based on this evaluation, may decide not to declare future dividends or otherwise return capital to shareholders, or may do so at levels that are less than anticipated.

Our capital return program may change from time to time, and we cannot guarantee we will continue to pay dividends or repurchase shares. Our announcement of capital return programs does not obligate us to pay any particular dividend amount (except with respect to dividends already declared) or repurchase any specific dollar amount or number of shares of common stock. A reduction, suspension or change in our capital return programs could have a negative effect on our stock price.

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 securities 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.

Tax law changes could have an adverse effect on our financial position, results of operations and cash flows.

As of December 31, 2022, we have fully released our tax valuation allowance and we anticipate incurring federal and state income taxes in 2023. In addition, substantive changes to existing federal income tax laws have been proposed that, if adopted, would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and would impose new taxes. The proposals include: repeal of the percentage depletion allowance for oil and gas properties; elimination of the ability to fully deduct intangible drilling costs in the year incurred; and an increase in the geological and geophysical amortization period for independent producers. Additional proposed general tax law changes include raising tax rates on both domestic and foreign income and imposing a new alternative minimum tax on book income. Further, many states are currently in deficits, and have been enacting laws eliminating or limiting certain deductions, carryforwards and credits in order to increase tax revenue. Should the U.S. or any relevant state pass tax legislation limiting any currently allowed tax incentives or deductions, our taxes would increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities. Since future changes to federal and state tax legislation and regulations are unknown, we cannot predict the ultimate impact such changes may have on our business.

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.

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 the date of the filing of this report that 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.

Following a self-audit of final reclamation activities associated with site retirements, we formally disclosed identified deficiencies to the Colorado Oil and Gas Conservation Commission ("COGCC") in December 2019. To resolve the alleged violations in July of 2021, the COGCC and PDC jointly agreed to an Administrative Order by Consent ("AOC") which assessed penalties in the amount of approximately $500,000, with approximately $350,000 suspended pending PDC meeting certain conditions of the AOC. We are implementing programs to meet the requirements of the AOC and correct any identified deficiencies.

Commencing in early 2020, we conducted a comprehensive air quality compliance audit over the facilities acquired in the SRC Acquisition. Through the self-audit process, we identified certain deficiencies and disclosed them to CDPHE and the EPA in July 2021. We do not believe potential penalties and other expenditures associated with the deficiencies identified will have a material effect on our financial condition or results of operations, but such penalties may exceed $300,000.

In August 2021 and November 2021, the COGCC issued us a Notice of Alleged Violation ("NOAV") related to the timing of wellhead pressure test reporting for certain wells in the Wattenberg Field. Pursuant to the NOAVs, we have conducted and submitted a comprehensive audit of our wellhead pressure testing and reporting processes. We have updated our processes to mitigate against the possibility of the alleged violations occurring in the future. We do not anticipate a material effect on our financial condition or results of operations. However, the potential penalties may exceed $300,000.

In June 2022, we received Compliance Advisories from the Colorado Air Pollution Control Division for alleged historical air quality violations over facilities acquired in the SRC Acquisition. In January 2023, we paid a total penalty of approximately $340,000 to resolve and settle the Compliance Advisories.

In July 2022, we received a Notice of Violation/Cease and Desist Order ("NOV") from the CDPHE, pursuant to a Great Western Operating Company May 2021 Stormwater Permit Audit and subsequent Compliance Advisory. Having acquired the Great Western assets on May 6, 2022, we are working with the CDPHE to ensure ongoing compliance and resolve the NOV. We do not anticipate potential penalties and other expenditures associated with the NOV will have a material effect on our financial condition or results of operations, but such penalties will likely exceed $300,000.

Clean Air Act Agreement and Related Consent Decree. While we continue to implement the requirements of a consent decree entered into with the EPA and CDPHE in 2017, such consent decree was terminated with no further penalties as of December 15, 2022.

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

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

Holders of Record

Our common stock, par value $0.01 per share, is traded on the NASDAQ Global Select Market under the symbol "PDCE". As of February 14, 2023, we had approximately 363 stockholders of record.

Dividend Policy

Our board of directors have authority to declare dividends to the holders of our common stock. Our board of directors intent is to continue the payment of dividends to the holders of our common stock in the future. However, the dividend program and payment of any future dividends 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 factors deemed relevant at the time to declare such dividends.

Additionally, our revolving credit facility, as well as the indentures governing our 6.125% senior notes due 2024 ("2024 Senior Notes") and our 5.75% senior notes due 2026 (the "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 certain other 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.

Repurchase of Equity Securities

The following table presents information about our purchases of our common stock during the year ended December 31, 2022:

Period	Total Number of Shares Purchased (1) (2)	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	592,567	$ 55.54	501,000	$ 159.5
February	71,735	56.73	4,340	1,250.0
March	825,680	69.71	820,555	1,192.8
April	714,091	74.22	613,658	1,147.4
May	1,382,199	69.33	1,381,407	1,051.6
June	970,777	75.74	970,777	978.1
July	866,538	58.71	864,738	927.3
August	2,187,393	63.38	2,187,240	788.7
September	1,153,214	62.22	1,153,214	716.9
October	718,215	67.82	714,088	668.5
November	1,797,291	76.78	1,785,771	531.3
December	1,148,300	66.69	1,148,300	454.7
Total purchases	12,428,000	$ 67.71	12,145,088	$ 454.7

(1) We reinstated our stock repurchase program in February 2021 and in February 2023, our board of directors approved a $750 million increase in the size of the program which we currently anticipate fully utilizing by December 31, 2025. Our stock repurchase program does not require any specific number of shares to be acquired, and can be modified or discontinued by our board of directors at any time.

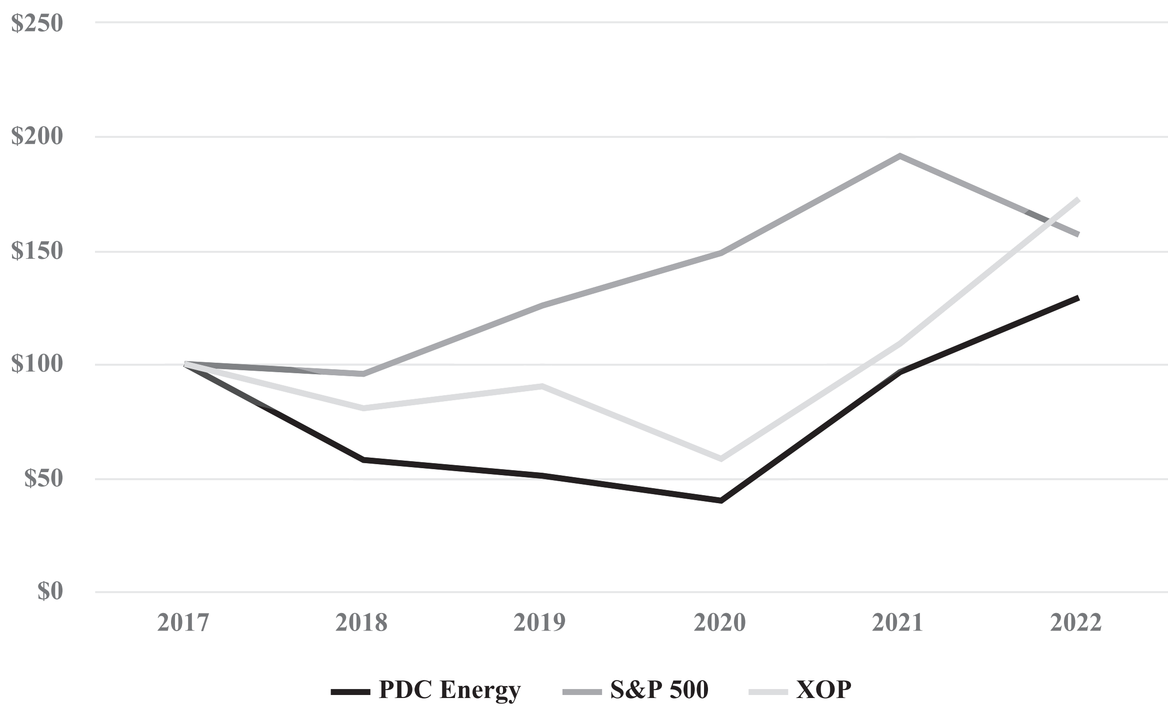
(2) Purchases outside of our stock repurchase program represent shares withheld from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans. The withheld shares are not considered common stock repurchased under the stock repurchase program.

Stockholder Performance Graph

The following performance graph and related information shall deemed to be furnished, but not filed with the SEC.

The graph below matches the cumulative 5-Year total return of our common stock with the cumulative total returns of the Standard and Poor’s 500 Index (“S&P 500 Index”) and Standard and Poor’s Oil and Gas Exploration and Production ETF (“XOP”). The cumulative total stockholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our common stock on December 31, 2017 and tracks it through December 31, 2022, in the S&P 500 Index and XOP on the same date. The results shown in the graph below are not necessarily indicative of future stock price performance.

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



	Year Ended December 31,					
	2017	2018	2019	2020	2021	2022
PDC Energy	100.00	57.74	50.78	39.83	96.43	129.22
S&P 500	100.00	95.62	125.72	148.85	191.58	156.89
XOP	100.00	80.50	90.17	58.24	108.95	172.69

ITEM 6. [RESERVED]

This Item has been omitted as we are no longer required to provide five years of selected financial data.

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 and liquidity from 2020 to 2021 has been omitted from this report but can be found in *Item 7. Management's Discussion and Analysis*, of our Annual Report on Form 10-K for the year ended December 31, 2021, filed with the SEC on February 28, 2022. Further, we encourage you to review the *Special Note Regarding Forward-Looking Statements* in Part I of this report.

EXECUTIVE SUMMARY

2022 Financial Overview of Operations and Liquidity

Market Conditions

The crude oil and natural gas industry is cyclical and commodity prices are inherently volatile. Commodity prices reflect global supply and demand dynamics as well as the geopolitical and macroeconomic environment. During 2022, crude oil and natural gas prices experienced high levels of volatility. NYMEX WTI spot prices for crude oil reached a high of $130.50 per barrel in March and a low of $70.08 per barrel in December and NYMEX Henry Hub spot prices for natural gas reached a high of $9.85 per MMBtu in August and a low of $3.46 per MMBtu in November. By the end of 2022, crude oil and natural prices had declined significantly from the levels seen earlier in the year.

Crude Oil Markets

During the first half of 2022, crude oil pricing generally increased due to increased demand, restrained OPEC+ production and uncertainties resulting from the Russian invasion of Ukraine. However, throughout 2022, the U.S. has experienced the highest inflation rates since 1981 resulting mainly from the global recovery from COVID-19, supply chain disruptions, higher labor costs, and higher energy costs. To address the increasing inflation rates, the U.S. Federal Reserve started increasing the benchmark federal funds interest rate. The magnitude and overall effectiveness of these actions remains uncertain, but such monetary policy changes can increase the risk of economic slowdown and/or lead to a recession. A slowdown or recession can cause a decrease in short-term or long-term demand for commodities, resulting in industry oversupply and a potential for lower commodity prices, which would impact our drilling program and further increase the volatility of our common stock price.

Natural Gas and NGL Markets

In addition to the crude oil market drivers noted above, natural gas and NGL prices are also affected by structural changes in supply and demand, growth in levels of liquified natural gas and liquified petroleum gas exports and deviations from seasonally normal weather. Europe's shift away from Russia's natural gas has led to Europe becoming increasingly dependent on U.S. LNG exports, creating new sources of demand for U.S. natural gas.

Lower inventory levels and lack of reinvestment in supply growth led to higher natural gas and NGL prices in 2022. However, a warmer winter in some parts of the world and a weakened economy has driven down the price of natural gas in early 2023.

Financial Matters

Year ended December 31, 2022

- Production volumes increased to 85.0 MMboe in 2022, an increase of 19 percent compared to 71.3 MMboe in 2021, primarily driven by production volumes from the Great Western Acquisition and as a result of our turn-in-line activities in 2022.

- Crude oil, natural gas and NGLs sales increased to $4.3 billion in 2022 compared to $2.6 billion in 2021, primarily due to a 41 percent increase in weighted average realized commodity prices and a 19 percent increase in production volumes between periods.

- Negative net cash settlements from our commodity derivative contracts increased to $880 million in 2022 compared to $410 million in 2021 due to continued improvement in commodity pricing year over year and additional commodity derivatives assumed in the Great Western Acquisition.

- Combined revenue from crude oil, natural gas and NGLs sales and net settlements from our commodity derivative instruments increased 59 percent to $3.4 billion from $2.1 billion in 2021.

- Net income increased to $1,778 million, or $18.49 per diluted share, compared to $522 million, or $5.22 per diluted share, in 2021, primarily due to (i) an increase in crude oil, natural gas and NGLs sales of $1,744 million, (ii) a $238 million decrease in net commodity risk management loss and (iii) a gain on bargain purchase in the Great Western Acquisition of $90 million. These positive factors were partially offset by (i) a $428 million increase in income tax expense (ii) a $253 million increase in production costs and (iii) a $115 million increase in depreciation, depletion and amortization expense between periods.

- Adjusted EBITDAX, a non-U.S. GAAP financial measure, was $2.7 billion compared to $1.6 billion in 2021, primarily due to an increase in sales of $1.3 billion, net of negative net derivative settlements, and a $90 million gain on bargain purchase recognized in 2022, partially offset by an increase in costs experienced in operations between periods.

- Cash flows from operations increased to $2.8 billion compared to $1.5 billion in 2021 primarily due to an increase in sales of $1.3 billion, net of negative net derivative settlements, partially offset by an increase in costs experienced in operations between periods. Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased to $2.5 billion compared to $1.5 billion in 2021. Adjusted free cash flows, a non-U.S. GAAP financial measure, increased to $1,421 million from $949 million in 2021.

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.

Great Western Acquisition

On May 6, 2022, we completed the acquisition of Great Western for approximately $1.4 billion, inclusive of Great Western's net debt. Great Western was an independent oil and gas company focused on the exploration, production and development of crude oil and natural gas in the Wattenberg Field of Colorado. The consideration paid was $542.5 million in cash and approximately 4.0 million shares of our common stock, valued at $293.3 million on the acquisition date. In addition, we paid off Great Western's secured credit facility totaling $235.8 million, and paid $361.2 million to terminate Great Western's 12 percent senior secured notes due 2025, inclusive of unpaid accrued interest and a premium for early termination. The cash portion of the purchase price and the termination of Great Western's debt was funded through a combination of cash on hand and availability under our revolving credit facility. As a result of the Great Western Acquisition, we acquired approximately 54,000 net acres in the core Wattenberg Field and production of approximately 50,000 Boe per day.

Drilling, Completion and Vertical Wells Abandonment Overview

In the Wattenberg Field, we operated one full-time drilling rig and one full-time completion crew during 2022, added a second full-time drilling rig in March 2022 and a third full-time drilling rig plus an intermittent completion crew in May 2022 upon closing the Great Western Acquisition. In addition, we operated one full-time drilling rig during 2022 and had one completion crew in the first half of 2022 in the Delaware Basin. Our total capital investments in crude oil and natural gas properties for the year ended December 31, 2022 were $1.1 billion. Pursuant to our plugging and abandonment program, we operated a full-time workover rig in the Wattenberg Field in 2022. The workover rig was focused on our legacy vertical wells to assist in our horizontal drilling program and to reduce our overall produced well emissions. Separate from our capital investments, we spent $21 million on this program in 2022.

The following table summarize our drilling, completion and vertical well abandonment activities for the year ended December 31, 2022:

	Operated Wells					
	Wattenberg Field		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
In-process as of December 31, 2021	143	133	21	21	164	154
Wells spud	174	161	13	13	187	174
Wells acquired in-process (1)	48	41	—	—	48	41
Wells turned-in-line	(164)	(150)	(19)	(19)	(183)	(169)
Developmental and exploratory dry hole	(1)	(1)	(3)	(3)	(4)	(4)
In-process as of December 31, 2022	200	185	12	12	212	197
Plugged and abandoned - Vertical Wells	253	244	—	—	253	244

(1) Represents in-process wells we obtained as part of the Great Western 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.

Capital Returns

Stock Repurchase Program. In February 2022, our board of directors approved a new stock repurchase program that reset the total repurchase value to $1.3 billion, which we currently anticipate fully utilizing by December 31, 2023. We repurchased 12.1 million shares of outstanding common stock at a cost of $823 million for the year ended December 31, 2022. As of December 31, 2022, $455 million remained available for repurchase under the program. In February 2023, our board of directors approved a $750 million increase in the size of the program, which we currently anticipate fully utilizing by December 31, 2025.

Dividends. Our board of directors approved the declaration and payment of a quarterly cash dividend of $0.25 per share of common stock in the first quarter of 2022 and increased our base quarterly dividend to $0.35 per share of common stock in the second quarter of 2022. In December 2022, our board of directors declared and paid a special dividend of $0.65 per share of our common stock in addition to the regular fourth quarter dividend. For the year ended December 31, 2022, our dividends declared totaled $184 million or $1.95 per share of outstanding common stock. In February 2023, our board of directors approved an increase in the quarterly base dividend from $0.35 to $0.40 per share.

2023 Operational and Financial Outlook

We anticipate that our production for 2023 will range between 255,000 Boe to 265,000 Boe per day, of which approximately 82,000 Bbls to 86,000 Bbls is expected to be crude oil. Our planned 2023 capital investments in crude oil and natural gas properties, which we expect to be between $1,350 million and $1,500 million, are focused on continued execution of our development plans in the Wattenberg Field and the Delaware Basin. Our 2023 capital budget and operating costs may continue to be impacted by cost inflation, supply chain constraints and availability of labor services.

We have 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 to best meet our short- and long-term corporate strategy. We may revise our 2023 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, 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 and acquisition and divestiture opportunities.

Wattenberg Field. We are drilling in the horizontal Niobrara and Codell plays in the rural areas of the core Wattenberg Field. Our 2023 capital investment program for the Wattenberg Field represents approximately 80 percent of our expected total capital investments in crude oil and natural gas properties. Our plan includes spudding and turning-in-line 200 to 225 operated wells. To meet our development plan, we intend on running three full-time horizontal drilling rigs and one full-time completion crew plus an intermittent completion crew during the year. As of December 31, 2022, we have approximately 200 gross operated DUCs and 915 approved permitted or CAP locations (i.e., locations that are contemplated by an approved CAP but still require approval under an OGDP).

Delaware Basin. Total capital investments in crude oil and natural gas properties in the Delaware Basin for 2023 are expected to be approximately 20 percent of our total capital investments. In 2023, we anticipate spudding and turning-in-line 15 to 25 operated wells.

We are committed to our disciplined approach to managing our development plans. Based on our current production forecast for 2023, we expect 2023 cash flows from operations to exceed our capital investments in crude oil and natural gas properties. Our first priority is to pay our quarterly base dividend of $0.40 per share. Then we expect to use approximately 60 percent or more of our remaining adjusted free cash flow, a non-U.S. GAAP financial measure, for share repurchases and special dividends, as needed. Any remaining adjusted free cash flows will be used for reducing debt and other general corporate purposes.

Regulatory and Political Updates

Colorado law requires an operator to obtain an OGDP prior to initiating development work relating to a well. The OGDP process streamlines single pad locations or proximate multi-pad locations into a single permitting package.

Operators in Colorado also have an option to pursue a CAP. A CAP is designed to represent an overview of oil and gas development over a larger area over a longer period of time through means including a comprehensive cumulative impact analysis, an alternative location analysis, and extensive communication with both local elected officials and communities. A CAP will include multiple OGDPs within its boundaries.

In June 2022, the COGCC granted PDC unanimous approval for a 69-well OGDP and a 30-well OGDP acquired in the Great Western Acquisition, our second and third approvals under the new Colorado permitting process. Additionally, in December 2022, the COGCC unanimously approved our first CAP, filed in December 2021, which encompasses approximately 450 wells in Weld County, Colorado. Following the approval of the CAP, we will submit individual OGDP packages for each of the locations within the CAP. The CAP, along with our prior OGDPs, represent the majority of our projected Wattenberg Field turn-in-line activity into 2028 based on our current pace and drilling plan in 2023.

Environmental, Social and Governance

We are committed to a meaningful and measurable ESG strategy. Our mission of being a cleaner, safer and more socially responsible company begins with a sound strategy, is supported in the boardroom and is overseen by our Environmental, Social, Governance and Nominating Committee at the board of directors, our internal Steering Committee and is considered at every level of our business.

We recognize the importance of reducing our environmental footprint and have created proactive programs and targets related to emission reduction. These initiatives, which include the plugging and abandonment of legacy vertical wells, retrofits of air pneumatics on older facilities, electrification of our facilities, transportation pipelines, technological innovations and other activities, require capital and operational investments which are proactively and regularly built into our annual budgeting process. In 2022, we spent approximately $80 million on ESG initiatives, which included (i) $20.5 million in plugging and abandonment costs for 243 vertical wells, (ii) approximately $20.0 million on emission reduction devices, such as electric drilling, air pneumatics and vapor recovery units on new and older wells, (iii) $10.5 million on the installment of water pipelines, and (iv) $5.0 million on giving, outreach and community relations. In 2023, additional environmental and compliance transition costs, such as emission reduction costs, are included in our budget. Some of our larger anticipated capital projects in 2023 include $10 million to $15 million for the installation of water pipelines primarily in Adams County, $20 million to $25 million for plugging and abandonment of approximately 250 legacy vertical wells and $15 million to $20 million for the continued increase of electrification in our operations.

As part of our ESG initiatives, we have set aggressive targets to (i) reduce greenhouse gas intensity by 60% from 2020 levels by 2025 and 74% by 2030, (ii) reduce methane emissions intensity by 50% from 2020 levels by 2025 and 70% by 2030, and (iii) eliminate routine flaring, as defined by World Bank, by 2025. In March 2022, we completed our EPA annual filing for 2021 emissions and reported an approximate 12% reduction in GHG emissions, an approximate 17% reduction in methane emissions intensity and an approximate 70% reduction in flared hydrocarbons from 2020 baseline levels (each on a per unit of production basis), putting us on track to meet our goals.

In May 2022, our board of directors approved quantitative metrics for GHG and methane emissions reductions for our 2022 short-term incentive program, including 15% GHG and 30% methane emissions reduction targets from 2021 to 2022. As noted above, this supports the Company's previously announced sustainability goals. In total, over 25% of our short-term incentive program in 2022 was tied to ESG and other environmental, health and safety initiatives. Our 2022 initial results indicate a reduction of over 30% in GHG and 50% in methane emissions from our 2021 levels.

In 2022 our board of directors was significantly engaged in our Sustainability reporting process, as it and our senior management team underwent its first TCFD process. Additionally, we filed our first Carbon Disclosure Project ("CDP") Climate Change Questionnaire, examining our future through a range of climate-focused scenarios. In September 2022, we issued our annual Sustainability reports. The reports include key metrics and data from 2021 operations and are aligned with Sustainable Accounting Standards Board ("SASB") standards and TCFD.

Additional information on our ESG practices, including sustainability goals, key metrics and progress achieved, can be found on the Sustainability page of our website at www.pdce.com. The information on our website, including the Sustainability reports, is not incorporated by reference in this report.

Results of Operations

Summary of Operating Results

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

	Year Ended December 31,				
				Percent Change	
	2022	2021	2020	2022-2021	2021-2020
	(dollars in millions, except per unit data)				
Production:					
Crude oil (MBbls)	27,486	22,682	23,720	21 %	(4)%
Natural gas (MMcf)	199,362	175,747	165,637	13 %	6 %
NGLs (MBbls)	24,325	19,360	17,042	26 %	14 %
Crude oil equivalent (MBoe)	85,038	71,333	68,368	19 %	4 %
Average Boe per day (Boe)	232,981	195,433	186,798	19 %	5 %
Crude Oil, Natural Gas and NGLs Sales:					
Crude oil	$ 2,578.2	$ 1,530.8	$ 816.8	68 %	87 %
Natural gas	984.5	519.6	178.8	89 %	191 %
NGLs	734.0	502.2	157.0	46 %	220 %
Total crude oil, natural gas and NGLs sales	$ 4,296.7	$ 2,552.6	$ 1,152.6	68 %	121 %
Net Settlements on Commodity Derivatives:					
Crude oil	$ (614.1)	$ (289.1)	$ 294.4	112 %	(198)%
Natural gas	(265.8)	(121.1)	(15.1)	119 %	*
Total net settlements on derivatives	$ (879.9)	$ (410.2)	$ 279.3	115 %	(247)%
Average Sales Price (excluding net settlements on derivatives):					
Crude oil (per Bbl)	$ 93.80	$ 67.49	$ 34.44	39 %	96 %
Natural gas (per Mcf)	4.94	2.96	1.08	67 %	174 %
NGLs (per Bbl)	30.17	25.94	9.21	16 %	182 %
Crude oil equivalent (per Boe)	50.53	35.78	16.86	41 %	112 %
Average Costs and Expense (per Boe):					
Lease operating expense	$ 3.09	$ 2.53	$ 2.36	22 %	7 %
Production taxes	3.67	2.32	0.87	58 %	167 %
Transportation, gathering and processing expenses	1.46	1.41	1.14	4 %	24 %
General and administrative expense	1.84	1.79	2.36	3 %	(24)%
Depreciation, depletion and amortization	8.82	8.90	9.06	(1)%	(2)%
Lease Operating Expense by Operating Region (per Boe):					
Wattenberg Field	$ 2.57	$ 2.19	$ 2.15	17 %	2 %
Delaware Basin	6.63	4.76	3.48	39 %	37 %

* *Percent change is not meaningful.*

Crude Oil, Natural Gas and NGLs Sales

Crude oil, natural gas and NGLs sales for the year ended December 31, 2022 increased compared to the year ended December 31, 2021 due to the following:

		Year Ended December 31, 2022
		(in millions)
Change in:		
Production	$	58.0
Increase in production from acquisitions		464.8
Average crude oil price		723.2
Average natural gas price		395.0
Average NGLs price		103.1
Total change in crude oil, natural gas and NGLs sales revenue	$	1,744.1

Crude Oil, Natural Gas and NGLs Production

The following table presents crude oil, natural gas and NGLs production for the periods presented:

	Year Ended December 31,			Percent Change	
Production by Operating Region	**2022**	**2021**	**2020**	**2022-2021**	**2021-2020**
Crude oil (MBbls)					
Wattenberg Field	23,082	18,901	19,552	22 %	(3)%
Delaware Basin	4,404	3,781	4,168	16 %	(9)%
Total	27,486	22,682	23,720	21 %	(4)%
Natural gas (MMcf)					
Wattenberg Field	175,040	154,150	140,845	14 %	9 %
Delaware Basin	24,322	21,597	24,792	13 %	(13)%
Total	199,362	175,747	165,637	13 %	6 %
NGLs (MBbls)					
Wattenberg Field	21,748	17,300	14,495	26 %	19 %
Delaware Basin	2,577	2,060	2,547	25 %	(19)%
Total	24,325	19,360	17,042	26 %	14 %
Crude oil equivalent (MBoe)					
Wattenberg Field	74,003	61,892	57,521	20 %	8 %
Delaware Basin	11,035	9,441	10,847	17 %	(13)%
Total	85,038	71,333	68,368	19 %	4 %
Average crude oil equivalent per day (Boe)					
Wattenberg Field	202,748	169,567	157,161	20 %	8 %
Delaware Basin	30,233	25,866	29,637	17 %	(13)%
Total	232,981	195,433	186,798	19 %	5 %

Net production volumes for crude oil, natural gas and NGLs increased 19 percent during the year ended December 31, 2022 compared to 2021. The increase in production volume between periods was primarily due to approximately 11.5 MMboe of additional production volumes as a result of the Great Western Acquisition and the net impact of turn-in-line activities in both basins since the fourth quarter of 2021. The increase was partially offset by normal decline in production from our existing wells.

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

Production Ratio by Operating Region	Year Ended December 31, 2022	2021	2020
Wattenberg Field			
Crude oil	31 %	31 %	34 %
Natural gas	40 %	41 %	41 %
NGLs	29 %	28 %	25 %
Total	100 %	100 %	100 %
Delaware Basin			
Crude oil	40 %	40 %	38 %
Natural gas	37 %	38 %	38 %
NGLs	23 %	22 %	24 %
Total	100 %	100 %	100 %

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.

The ultimate timing and availability of adequate infrastructure remains out of our control. Weather, regulatory developments, preventative routine maintenance 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 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.

Our production from the Wattenberg Field and the Delaware Basin was not materially affected by midstream or downstream capacity constraints during the year ended December 31, 2022. We continuously monitor infrastructure capacities versus producer activity and production volume forecasts. Increases in crude oil and natural gas prices in 2022 have incentivized producers in the Permian Basin to increase the level of drilling and completion activities. The increase in production levels and continued increase in development may lead to natural gas transportation constraints out of the Permian Basin in 2023, which may result in lower realized Waha natural gas prices. However, approximately half of PDC's gas production in the Delaware Basin is dedicated to the Permian Highway Pipeline and is exposed to Houston-based gas pricing. We believe that this reduces the risk of a decrease in realized natural gas prices related to transportation constraints.

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.

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	**Year Ended December 31,**			**Percent Change**	
(excluding net settlements on derivatives)	**2022**	**2021**	**2020**	**2022-2021**	**2021-2020**
Crude oil (per Bbl)					
Wattenberg Field	$ 93.34	$ 67.49	$ 34.21	38 %	97 %
Delaware Basin	96.22	67.47	35.48	43 %	90 %
Weighted average price	93.80	67.49	34.44	39 %	96 %
Natural gas (per Mcf)					
Wattenberg Field	4.97	2.98	1.22	67 %	144 %
Delaware Basin	4.68	2.81	0.28	67 %	*
Weighted average price	4.94	2.96	1.08	67 %	174 %
NGLs (per Bbl)					
Wattenberg Field	28.24	24.77	8.84	14 %	180 %
Delaware Basin	46.46	35.72	11.32	30 %	216 %
Weighted average price	30.17	25.94	9.21	16 %	182 %
Crude oil equivalent (per Boe)					
Wattenberg Field	49.18	34.95	16.84	41 %	108 %
Delaware Basin	59.58	41.25	16.94	44 %	144 %
Weighted average price	50.53	35.78	16.86	41 %	112 %

* *Percent change is not meaningful.*

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.

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 ("TGP") expense.

Information related to the components and classifications of TGP expense on 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 TGP expense shown in the table below represents our approximate composite per barrel price for NGLs for the periods presented.

2022	Average NYMEX Price	Average Realized Price Before TGP Expense	Average Realization Percentage Before TGP Expense	Average TGP Expense[(1)]	Average Realized Price After TGP Expense	Average Realization Percentage After TGP Expense
Crude oil (per Bbl)	$ 96.98	$ 96.72	100 %	$ 2.58	$ 94.14	97 %
Natural gas (per MMBtu)	6.78	5.06	75 %	0.21	4.85	72 %
NGLs (per Bbl)	96.98	31.95	33 %	—	31.95	33 %
Crude oil equivalent (per Boe)	74.98	52.23	70 %	1.32	50.91	68 %

2021	Average NYMEX Price	Average Realized Price Before TGP Expense	Average Realization Percentage Before TGP Expense	Average TGP Expense[(1)]	Average Realized Price After TGP Expense	Average Realization Percentage After TGP Expense
Crude oil (per Bbl)	$ 67.92	$ 67.49	99 %	$ 3.10	$ 64.39	95 %
Natural gas (per MMBtu)	3.76	2.96	79 %	0.13	2.83	75 %
NGLs (per Bbl)	67.92	25.94	38 %	—	25.94	38 %
Crude oil equivalent (per Boe)	49.29	35.78	73 %	1.30	34.48	70 %

2020	Average NYMEX Price	Average Realized Price Before TGP Expense	Average Realization Percentage Before TGP Expense	Average TGP Expense[(1)]	Average Realized Price After TGP Expense	Average Realization Percentage After TGP Expense
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 %

(1) *Average TGP expense excludes unutilized firm transportation fees of $0.14, $0.11, and $0.04 per Boe for the years ended December 31, 2022, 2021, and 2020, respectively.*

Our average realization percentage for crude oil equivalent was relatively consistent in 2022 as compared to 2021 due to the overall increases in commodity prices between periods and realized improved differentials from our 2022 crude oil sales contracts. This was offset by a weakening Mont Belvieu price in the second half of 2022, impacting our realized price for NGLs and higher TGP rates for our natural gas production.

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 swaps. 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, 2022.

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,		
	2022	2021	2020
		(in millions)	
Commodity price risk management gain (loss), net:			
Net settlements of commodity derivative instruments:			
Crude oil collars and fixed price exchanges	$ (614.1)	$ (289.1)	$ 294.4
Natural gas collars and fixed price exchanges	(288.0)	(120.1)	(1.4)
Natural gas basis protection exchanges	22.2	(1.0)	(13.7)
Total net settlements of commodity derivative instruments	(879.9)	(410.2)	279.3
Change in fair value of unsettled commodity derivative instruments:			
Reclassification of settlements included in prior period changes in fair value of commodity derivative instruments	287.0	49.3	(19.9)
Crude oil collars and fixed price exchanges	103.5	(269.3)	(49.8)
Natural gas collars and fixed price exchanges	55.4	(61.7)	(7.8)
Natural gas basis protection exchanges	(29.6)	(9.6)	(21.5)
Net change in fair value of unsettled commodity derivative instruments	416.3	(291.3)	(99.0)
Total commodity price risk management gain (loss), net	$ (463.6)	$ (701.5)	$ 180.3

The significant increase in commodity prices during 2022 had an overall unfavorable impact on the fair value and settlements of our commodity derivatives.

Lease Operating Expense

Lease operating ("LOE") expense increased by 46 percent to $263.0 million in 2022 compared to $180.7 million in 2021. The period-over-period increase in LOE was primarily due to (i) an approximate $30.0 million increase from operated wells acquired in the Great Western Acquisition, (ii) an increase of $20.0 million from increased activity and the impact of inflation in the Wattenberg Field, (iii) a $15.2 million increase in workover expense relating to activities mainly in the Delaware Basin and (iv) a $12.5 million increase in chemical treatments, water disposal and well services in the Delaware Basin as a result of increased activity and the impact of inflation. LOE per Boe increased 22 percent to $3.09 in 2022 from $2.53 in 2021 primarily due to the additional costs outlined above.

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 increased 89 percent to $311.8 million in 2022 compared to $165.2 million in 2021. The increase in production taxes was primarily due to an increase in crude oil, natural gas and NGLs sales between periods. Production taxes per Boe increased 58 percent to $3.67 in 2022 compared to $2.32 in 2021.

Transportation, Gathering and Processing Expense

TGP expense increased 24 percent to $124.6 million in 2022 compared to $100.4 million in 2021. The increase in TGP expense between periods was primarily due to an increase in gas processing volumes and higher rates in the Delaware Basin. TGP per Boe was $1.46 and $1.41 for 2022 and 2021, respectively.

Exploration, Geologic, and Geophysical Expense

Exploration, geologic and geophysical expense increased to $13.1 million in 2022 compared to $1.1 million in 2021. In 2022, we drilled and turned-in-line an exploratory well in the Delaware Basin that was not economically viable. During 2022, we expensed the associated lease costs and related infrastructure assets of the exploratory dry hole at a cost of $12.0 million.

Impairment of Properties and Equipment

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

	Year Ended December 31,		
	2022	2021	2020
		(in millions)	
Impairment of proved and unproved properties	$ 6.8	$ 0.4	$ 881.2
Impairment of infrastructure and other	—	—	1.2
Total impairment of properties and equipment	$ 6.8	$ 0.4	$ 882.4

There were no significant impairment charges recognized in relation to our proved and unproved oil and gas properties in 2022 or 2021. If crude oil prices were to 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.

During the first quarter of 2020, we recorded impairment charges of $881.1 million to our proved and unproved properties in the Delaware Basin. These impairment charges were due to a significant decline in crude oil prices, which was considered a triggering event that required us to assess our crude oil and natural gas properties for possible impairment.

General and Administrative Expense

General and administrative expense increased to $156.3 million in 2022 compared to $127.7 million in 2021 primarily due to $18.2 million in transaction and transition costs relating to the Great Western Acquisition and a $6.4 million increase related to salaries, wages and benefits as a result of an increase in headcount from the Great Western Acquisition along with an increase in drilling activity.

Depreciation, Depletion and Amortization Expense

Crude oil and natural gas properties. During 2022 and 2021, we invested $1,107.7 million and $583.6 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 $741.9 million and $627.5 million in 2022 and 2021, respectively. The increase in total DD&A expense was primarily due to a 19 percent increase in production volumes between periods driven by the Great Western Acquisition. The increase was partially offset by a decrease in weighted average depletion rate resulting from the improved reserve quantities as of December 31, 2022 as a result of increased commodity prices in 2022.

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

	Year Ended December 31, 2022
	(in millions)
Increase in production	$ 120.3
Decrease in weighted average depletion rate	(5.9)
Total decrease in DD&A expense related to crude oil and natural gas properties	$ 114.4

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

	Year Ended December 31,		
	2022	2021	2020
		(per Boe)	
Operating Region/Area			
Wattenberg Field	$ 8.48	$ 8.68	$ 8.80
Delaware Basin	10.39	9.59	9.68
Total weighted average DD&A expense rate	8.72	8.80	8.94

Non-crude oil and natural gas properties. Depreciation expense for non-crude oil and natural gas properties was $7.8 million for the year ended December 31, 2022, compared to $7.7 million for the year ended December 31, 2021.

Interest Expense, net

Interest expense, net decreased by $18.0 million to $64.7 million in 2022 compared to $82.7 million in 2021. The decrease was primarily due to (i) a $17.8 million decrease from a partial redemption of our 2024 Senior Notes and a full redemption of Convertible Notes and certain Senior Notes in the second half of 2021, (ii) a $6.9 million loss on extinguishment recognized in 2021 relating to the redemption of certain other Senior Notes and (iii) an $8.0 million decrease in debt issuance cost amortization as a result of debt expiration and redemptions in 2021. These decreases were partially offset by an $18.4 million increase relating to increased borrowings under our revolving credit facility in 2022 to finance the cash portion of the purchase price of the Great Western Acquisition as well as an overall increase in interest rates on our credit facility.

Gain on Bargain Purchase

We recognized a $90.1 million gain on the bargain purchase of the Great Western Acquisition, net of related income taxes of $28.4 million, in 2022. For additional information, see *Note 3 - Business Combination* in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report.

Provision for Income Taxes

We recorded income tax expense of $454.2 million and $26.6 million for 2022 and 2021, respectively, resulting in effective tax rates of 20.3 percent and 4.8 percent on the respective pre-tax income. The effective tax rates differ from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21 percent to the pre-tax income due to state income taxes and changes in the valuation allowance against our deferred income tax assets.

We consider whether a portion, or all, of our deferred tax assets ("DTAs") will be realized based on a more likely than not standard of judgment. The ultimate realization of DTAs 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 available taxes in carryback periods, the future reversals of existing taxable temporary differences, tax planning strategies and projected future taxable income in making this assessment. Our oil and gas property impairments and cumulative pre-tax losses were key considerations that led us to provide a valuation allowance against our DTAs beginning January 1, 2020 since we previously could not conclude that it is more likely than not that our DTAs will be fully realized in future periods.

As we previously disclosed, we maintained a valuation allowance on our net federal deferred tax assets and continued to do so until sufficient positive evidence existed to support a reversal of the allowance. In 2022, continued higher commodity prices increased our income, resulting in the reversal of objective negative evidence of cumulative loss in recent years, and we determined that we have sufficient positive evidence to release the valuation allowance. As a result, we released the full valuation allowance of $56.6 million against our deferred income tax assets and recognized a corresponding decrease to income tax expense.

Given recent improvements in oil and gas prices and assumptions based on our current production forecasts, we estimate that we will incur federal and state cash income taxes in 2023.

In August 2022, the IRA was signed into law. The IRA includes implementation of a new alternative minimum tax, an excise tax on stock buybacks, and significant tax incentives for energy and climate initiatives, among other provisions. The alternative minimum tax and excise tax on stock buyback provisions are effective for tax years beginning after December 31, 2022. We continue to monitor updates to the IRA and the impact of the IRA on our financial position, results of operations and liquidity. We do not believe the IRA will have a material impact on our stock buyback program or our financial position in 2023, however, we are still assessing the impact for subsequent years.

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

The factors impacting net income of $1,778 million and $522 million in 2022 and 2021, respectively, are discussed above.

Adjusted net income, a non-U.S. GAAP financial measure, was $1,450 million and $800 million for the year ended December 31, 2022 and 2021, respectively. With the exception of the tax-affected (when applicable) net change in fair value of unsettled derivatives, the same factors impacted adjusted net income. 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

Overview

Our primary sources of liquidity are cash and cash equivalents, cash flows from operating activities, unused borrowing capacity from our revolving credit facility, proceeds raised in debt and equity capital market transactions and other sources, such as asset sales.

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, capital returns 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. These activities typically result in a working capital deficit; however, we do not believe that our working capital deficit as of December 31, 2022 is an indication of a lack of liquidity. We had working capital deficits of $826 million and $462 million at December 31, 2022 and 2021, respectively. The increase in working capital deficit since December 31, 2021 primarily was a result of the Great Western Acquisition and a significant increase in production taxes payable due to increase in sales between periods. 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.

From time to time, we may 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.

Liquidity

Our cash and cash equivalents were $6.5 million at December 31, 2022 and availability under our revolving credit facility was $1.1 billion, providing for total liquidity of $1.1 billion as of December 31, 2022. The borrowing base is primarily based on the loan value assigned to the proved reserves attributable to our crude oil and natural gas interests.

Our material short-term and long-term cash requirements consist primarily of capital expenditures, payments of contractual obligations, dividends, share repurchases, income taxes and working capital obligations. If commodity prices increase, our working capital requirements may increase due to higher operating costs and negative settlements on our outstanding commodity derivative contracts. Funding for these requirements may be provided by any combination of our capital resources previously outlined.

As a result of the Great Western Acquisition, we paid $361 million on Great Western's behalf to pay and discharge Great Western's 12% senior secured notes due 2025, inclusive of unpaid accrued interest and a premium for early termination. Additionally, we paid $236 million on Great Western's behalf to pay Great Western's secured credit facility, inclusive of unpaid accrued interest. The termination of Great Western's debt was funded through a combination of cash on hand and availability under our revolving credit facility.

Based on our current production forecast for 2023, we expect 2023 cash flows from operations to exceed our capital investments in crude oil and natural gas properties. In addition, 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 fund our planned activities through the 12-month period following the filing of this report. We also believe that we will have sufficient expected cash flows from operations to allow us to execute our capital return plan. Future repurchases of common stock or dividend payments will be subject to approval by our board of directors and will depend on our level of earnings, financial requirements, and other factors considered relevant by our board.

Our material long-term cash requirements relate to debt obligations and interest payments, commodity derivative contract liabilities, production taxes, operating and finance leases, asset retirement obligations and firm transportation and processing agreements included in *Item 8. Financial Statements and Supplementary Data* to our consolidated financial statements included elsewhere in this report.

In October 2022, as part of the semi-annual redetermination of the borrowing base under our credit facility, the borrowing base increased from $3.0 billion to $3.5 billion, primarily due to the addition of the reserves acquired from Great Western; however, we maintained our elected commitment level of $1.5 billion. 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 (a) to maintain a minimum current ratio of 1.0:1.0 and (b) not exceed a maximum leverage ratio of 3.5:1.0. 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 and excludes the fair value of commodity derivative assets. Additionally, the current ratio covenant calculation allows us to exclude the fair value of commodity derivative liabilities and 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, 2022, we were in compliance with all covenants in the revolving credit facility with a current ratio of 1.5:1.0 and a leverage ratio of 0.5:1.0.

We expect to remain in compliance with the covenants under our credit facility and our Senior Notes throughout the 12-month period following the filing of this report.

Cash Flows

Our cash flows from operating, investing and financing activities are as follows:

	Year ended December 31,		
	2022	2021	2020
		(in thousands)	
Cash flows from operating activities	$ 2,772,324	$ 1,547,796	$ 870,079
Cash flows from investing activities	(2,149,516)	(578,804)	(687,159)
Cash flows from financing activities	(650,143)	(937,786)	(181,260)
Net increase (decrease) in cash and cash equivalents	$ (27,335)	$ 31,206	$ 1,660

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 $1,225 million to $2,772 million in 2022 as compared to $1,548 million in 2021. The increase between periods was primarily due to a $1,744 million increase in crude oil, natural gas and NGLs sales and changes in the timing of receivable collections. These increases were partially offset by a $470 million increase in cash settlement losses on commodity derivatives, a $147 million increase in production taxes, an $82 million increase in lease operating expenses and changes in the timing of vendor and royalty owner payments between periods.

Adjusted cash flows from operations, a non-U.S. GAAP financial measure, increased by $1,006 million in 2022 to $2,538 million from $1,533 million in 2021. 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 $472 million in 2022 to $1,421 million from $949 million in 2021. The increase was primarily due to the increase in cash flows from operating activities, as discussed above, partially offset by an increase in capital investments in crude oil and natural gas properties as a result of our 2022 development plan.

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 in 2022 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 $2,150 million during 2022 was primarily due to $1,068 million utilized for the Great Western Acquisition and drilling and completion activities of $1,070 million, partially offset by $16 million in proceeds from the sale of certain properties and equipment.

Net cash used in investing activities of $579 million during 2021 was primarily related to our drilling and completion activities of $583 million, partially offset by $5 million in proceeds from the sale of certain properties and equipment.

Financing Activities. Net cash used in financing activities in 2022 of $650 million was primarily due to (i) the repurchase of 12.1 million shares of our common stock for $818 million pursuant to our stock repurchase program and (ii) dividend payments totaling $182 million, partially offset by net borrowings on our credit facility of $370 million to fund the cash portion of the purchase price of the Great Western Acquisition and to terminate Great Western's debt. As of December 31, 2022, $455 million out of the approved $1.3 billion remained available for stock repurchases under the program. In February 2023, our board of directors approved a $750 million increase in the size of the program. Future repurchases of common stock or dividend payments will be subject to approval by our board of directors and will depend on our level of earnings, financial requirements, and other factors considered relevant by our board.

Net cash used in financing activities in 2021 of $938 million was primarily due to (i) net repayments on our credit facility of $168 million, (ii) redemption and retirement of Convertible Notes and other Senior Notes totaling $509 million, (iii) the repurchase of 3.8 million shares of our common stock for $157 million pursuant to our stock repurchase program and (iv) dividend payments totaling $84 million.

Subsidiary Guarantors

PDC Permian, Inc., a Delaware corporation ("Permian"), and Pioneer Water Pipeline LLC, a Delaware limited liability company ("Pioneer" and together with Permian, the "Guarantors"), each a wholly-owned subsidiary, guarantees our obligations under our 2024 Senior Notes and 2026 Senior Notes (collectively, the "Senior Notes"). Permian holds our assets located in the Delaware Basin. Pioneer holds certain water midstream assets located in the Wattenberg Field. The Senior Notes are fully and unconditionally guaranteed on a joint and several basis by the Guarantors. 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: (i) incur additional debt including under our revolving credit facility, (ii) make certain investments or pay dividends or distributions on our capital stock or purchase, redeem or retire capital stock, (iii) sell assets, including capital stock of our restricted subsidiaries, (iv) restrict the payment of dividends or other payments by restricted subsidiaries to us, (v) create liens that secure debt, (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company.

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

	As of/Year Ended December 31,			
	2022		2021	
	Issuer	Guarantors	Issuer	Guarantor
	(in millions)			
Assets				
Current assets	$ 539.1	$ 54.7	$ 402.6	$ 56.0
Intercompany accounts receivable, guarantor subsidiary	—	334.2	—	40.8
Investment in guarantor subsidiary	1,766.8	—	1,767.2	—
Properties and equipment, net	6,286.4	1,007.0	3,875.0	939.9
Other non-current assets	88.0	7.7	58.5	4.8
Liabilities				
Current liabilities	$ 1,361.5	$ 58.7	$ 862.5	$ 57.6
Intercompany accounts payable	334.2	—	27.9	—
Long-term debt	1,314.0	—	942.1	—
Other non-current liabilities	1,101.7	164.1	392.3	172.0
Statement of Operations				
Crude oil, natural gas and NGLs sales	$ 3,639.3	$ 657.4	$ 2,163.1	$ 389.5
Commodity price risk management gain (loss), net	(463.6)	—	(701.5)	—
Total revenues	3,179.7	666.0	1,464.5	391.4
Production costs	1,167.4	281.6	892.4	189.0
Gross profit (1)	2,471.9	375.8	1,270.7	200.4
Impairment of properties and equipment	0.8	5.9	0.4	—
Net income (loss)	1,419.5	358.6	327.7	194.9

(1) Gross profit is calculated as crude oil, natural gas and NGLs sales less production costs.

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.

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. The following discussion outlines the accounting policies and practices involving the use of estimates and application of significant judgment that are critical in determining our financial results. Changes in the estimates and assumptions discussed below could materially affect the amount or timing of our financial results.

Crude Oil and Natural Gas Reserve Quantities

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. The successful efforts method inherently relies on the estimation of proved crude oil, natural gas and NGL reserves. In determining the estimates of reserve and economic evaluations, management utilizes specialists, specifically petroleum engineers. 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 estimates of 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, we continually make revisions to reserve estimates as additional information becomes available. We cannot predict the amounts or timing of such future revisions.

If the estimates of proved reserve quantities decline, the rate at which we record depletion expense will increase, which would reduce future net income. Changes in depletion rate calculations caused by changes in reserve quantities are made prospectively. In addition, a decline in reserve estimates may impact the outcome of our assessment of proved and unproved properties for impairment. Impairments are recorded in the period in which they are identified.

We cannot predict future commodity prices. However, we performed a sensitivity analysis on our proved reserve estimates as of December 31, 2022, to present a decrease of approximately 20 percent in crude oil price (and holding all other factors constant), as the value of crude oil influences the value of our proved reserves most significantly. As a result, our proved reserve quantities would decrease by 7.8 MMBoe or 1 percent. The decrease would have increased our DD&A rate by $0.03 per Boe and decreased our pre-tax income by $2.2 million for the year ended December 31, 2022. This estimated impact is based on available data as of December 31, 2022, and future events could require different adjustments to our DD&A rate. During 2022 and 2021, we had positive revisions to our proved reserve quantities of 29.8 MMBoe and 52.9 MMBoe, respectively, as a result of higher average prices for crude oil, natural gas and NGLs. During 2020 we had a negative revision of 39.5 MMBoe as a result of lower average prices for crude oil, natural gas and NGLs. For more information regarding reserve estimations, including additional crude oil sensitives and descriptions over historical reserve revisions, see *Items 1 and 2. Business and Properties - Oil and Gas Production and Operations* and *Supplemental Oil and Gas Information* within our consolidated financial statements included in *Item 8. Financial Statements and Supplementary Data* included elsewhere in this report.

Impairment of Crude Oil and Natural Gas Properties

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. 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 discount factor. 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, and other factors that management believes will impact realizable prices. 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.

Unproved properties with individually significant acquisition costs are periodically assessed for impairment and reduced to fair value based on a review over our future development plans, estimated future cash flows for probable well locations and remaining average lease terms. Items that can impact our future development plans can be driven by drilling results, reservoir performance, capital resources and seismic interpretations. Changes in our assumptions of the estimated nonproductive portion of our undeveloped leases could result in additional impairment expense.

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. We cannot predict when or if future impairment charges will be recorded because of the uncertainty in the factors discussed above.

There were no significant impairment charges recognized related to our proved and unproved properties during the years ended December 31, 2022 or 2021. We recorded impairment charges of $881.1 million to our proved and unproved properties to our Delaware Basin properties in 2020 as a result of a significant decline in crude oil prices.

Valuation of Business Combinations

We follow the acquisition method of accounting for business combinations. Assets acquired and liabilities assumed are recognized at the date of acquisition at their respective estimated fair values. Any excess of the purchase price over the fair value amounts assigned to assets and liabilities is recorded as goodwill. Any deficiency of the purchase price over the estimated fair values of the net assets acquired is recorded as a gain in statements of operations.

In connection with the Great Western Acquisition in 2022, we allocated $1.5 billion of purchase price consideration to the assets acquired and liabilities assumed based on estimated fair values as of the acquisition date. 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. The Great Western Acquisition resulted in a gain on bargain purchase due to the estimated fair value of the identifiable net assets acquired exceeding the purchase consideration transferred by $90.1 million, net of related income taxes of $28.4 million. The bargain purchase was primarily attributable to the increase in commodity price forecasts from the date we entered into the definitive purchase agreement, February 26, 2022, to the closing date of the acquisition, May 6, 2022, when the fair value of the crude oil and natural gas reserves acquired was determined. Additionally, the majority of the acquisition consideration was fixed and therefore did not fluctuate as a result of market increases or decreases between the date of entry into the agreement through the closing date. Assuming all factors are held constant, an approximate 10 percent decrease in future commodity prices used in the valuation of the proved crude oil and natural gas properties would reduce the fair value by approximately $400 million, recognition of approximately $300 million of goodwill and no gain on bargain purchase.

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.

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.

Recent Accounting Pronouncements

There were no significant new accounting standards adopted or new accounting pronouncements that would have potential effect on us as of December 31, 2022.

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.

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 for the periods presented:

	Year Ended December 31,		
	2022	2021	2020
		(thousands)	
Cash flows from operations to adjusted cash flows from operations and adjusted free cash flow:			
Net cash from operating activities	$ 2,772.3	$ 1,547.8	$ 870.1
Changes in assets and liabilities	(233.9)	(15.2)	51.5
Adjusted cash flows from operations	2,538.4	1,532.6	921.6
Capital expenditures for development of crude oil and natural gas properties	(1,069.5)	(583.1)	(551.0)
Capital expenditures for midstream assets	(10.1)	—	—
Change in accounts payable related to capital expenditures for oil and gas development activities and midstream assets	(38.2)	(0.5)	28.7
Adjusted free cash flow	$ 1,420.6	$ 949.0	$ 399.3
Net income (loss) to adjusted net income (loss):			
Net income (loss)	$ 1,778.1	$ 522.3	$ (724.3)
Loss (gain) on commodity derivative instruments	463.6	701.5	(180.3)
Net settlements on commodity derivative instruments	(879.9)	(410.2)	279.3
Tax effect of above adjustments [(1)]	88.3	(14.0)	—
Adjusted net income (loss)	$ 1,450.1	$ 799.6	$ (625.3)
Net income (loss) to adjusted EBITDAX:			
Net income (loss)	$ 1,778.1	$ 522.3	$ (724.3)
Loss (gain) on commodity derivative instruments	463.6	701.5	(180.3)
Net settlements on commodity derivative instruments	(879.9)	(410.2)	279.3
Non-cash stock-based compensation	26.8	23.0	22.2
Interest expense, net	64.7	82.7	88.7
Income tax expense (benefit)	454.2	26.6	(7.9)
Impairment of properties and equipment	6.8	0.4	882.4
Exploration, geologic and geophysical expense	13.1	1.1	1.4
Depreciation, depletion and amortization	749.7	635.2	619.7
Accretion of asset retirement obligations	13.4	12.1	10.1
Loss (gain) on sale of properties and equipment	0.2	(0.9)	(0.7)
Adjusted EBITDAX	$ 2,690.7	$ 1,593.8	$ 990.6

	Year Ended December 31,		
	2022	2021	2020
	(thousands)		
Cash from operating activities to adjusted EBITDAX:			
Net cash from operating activities	$ 2,772.3	$ 1,547.8	$ 870.1
Gain on bargain purchase	90.1	—	—
Interest expense, net [(2)]	64.7	75.8	88.7
Amortization and write-off of debt discount, premium and issuance costs	(5.4)	(13.5)	(16.8)
Exploration, geologic and geophysical expense [(3)]	1.1	1.1	1.4
Other	1.8	(2.2)	(4.3)
Changes in assets and liabilities	(233.9)	(15.2)	51.5
Adjusted EBITDAX	$ 2,690.7	$ 1,593.8	$ 990.6
PV-10:			
Standardized measure of discounted future net cash flows	$ 14,987.4	$ 7,908.2	$ 3,282.2
Present value of estimated future income tax discounted at 10%	4,065.6	1,800.6	172.4
PV-10	$ 19,053.0	$ 9,708.8	$ 3,454.6

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(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.
(2) Excludes loss on extinguishment from early retirement of our senior notes amounting to $6.9 million for the year ended December 31, 2021.
(3) Excludes exploratory dry hole costs of $12.0 million for the year ended December 31, 2022.

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. Recent inflationary trends and the possibility of a recession could impact each of these market risks. 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 2024 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, 2022, we had $370.0 million of outstanding borrowings under our revolving credit facility. If market interest rates had increased or decreased one percent, our interest expense for the year ended December 31, 2022 would have been changed by approximately $4.3 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.

As of December 31, 2022, we had a net liability derivative position of $270.3 million related to our commodity price risk derivatives. Based on a sensitivity analysis as of December 31, 2022, we estimate that a 10 percent increase in crude oil prices and natural gas prices, inclusive of basis, over the entire period for which we have commodity derivatives in place would have resulted in an increase in the fair value of our net derivative liabilities of $144.4 million, whereas a 10 percent decrease in prices would have resulted in a decrease in the fair value of our net derivative liabilities of $143.2 million. The potential increase in the fair value of our net derivative liabilities would be recorded in our 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. For the year ended December 31, 2022, one customer accounted for more than 10% of our sales. For the years ended December 31, 2021 and 2020, three and four customers, respectively, accounted for more than 10% of our sales. Our allowances for credit losses were insignificant as of December 31, 2022.

Disclosure of Limitations

Because the information above included only those exposures that existed at December 31, 2022, 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, 2022 and 2021, and the related consolidated statements of operations, of stockholders' equity and of cash flows for each of the three years in the period ended December 31, 2022, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 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, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

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 Crude 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, net balance was $11.3 billion as of December 31, 2022, and depreciation, depletion and amortization (DD&A) expense for the year ended December 31, 2022 was $749.7 million. 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. As disclosed by management, significant inputs and engineering assumptions used in developing the estimates of proved crude oil and natural gas reserves include estimates of 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. In determining the estimates of reserve and economic evaluations, management utilizes specialists, specifically petroleum engineers.

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 natural 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 judgment, 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.

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 management's specialists was used in performing the procedures to evaluate the reasonableness of the proved crude oil and natural gas reserves. 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 evaluating the methods and assumptions used by the specialists, testing the completeness and accuracy of the data used by the specialists and evaluating the specialists' findings.

Acquisition of Great Western Petroleum, LLC - Valuation of Proved Crude Oil and Natural Gas Properties, Net

As described in Notes 2 and 3 to the consolidated financial statements, on May 6, 2022, the Company completed the acquisition of Great Western Petroleum, LLC for $1.4 billion. The acquisition resulted in the recognition of $2.1 billion in proved crude oil and natural gas properties, net. Management utilizes the acquisition method to account for acquisitions of businesses and pursuant to the acquisition method, allocates the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. 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. In determining the estimates of reserve and economic evaluations, management utilizes specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the valuation of proved crude oil and natural gas properties, net acquired in the acquisition of Great Western Petroleum, LLC is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the fair value estimate of the proved crude oil and natural gas properties acquired, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating management's inputs and assumptions related to reserves volumes, future operating and development costs, future commodity prices, and the market based 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 acquisition accounting, including controls over the fair value estimate of proved crude oil and natural gas properties acquired. These procedures also included, among others (i) reading the purchase agreement, (ii) testing management's process for developing the fair value estimate of proved crude oil and natural gas properties acquired, (iii) evaluating the appropriateness of the discounted cash flow models, (iv) testing the completeness and accuracy of the underlying data used in the discounted cash flow models, and (v) evaluating the reasonableness of the significant inputs and assumptions used by management related to reserves volumes, future operating and development costs, future commodity prices, and the market based weighted average cost of capital rate. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the reserves volumes used in the discounted cash flow models. 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 evaluating the methods and assumptions used by the specialists, testing of the completeness and accuracy of the data used by the specialists and evaluating the specialists' findings. Evaluating the reasonableness of management's inputs and assumptions related to future operating and development costs and future commodity prices involved evaluating whether the inputs and assumptions used by management were reasonable considering past and anticipated performance of the Company and Great Western Petroleum, LLC and observable market data. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the discounted cash flow models and the reasonableness of the market based weighted average cost of capital rate assumption.

/s/ PricewaterhouseCoopers LLP
Denver, Colorado
February 22, 2023

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, 2022	December 31, 2021
Assets		
Current assets:		
Cash and cash equivalents	$ 6,494	$ 33,829
Accounts receivable, net	546,311	398,605
Fair value of derivatives	31,963	17,909
Prepaid expenses and other current assets	8,987	8,230
Total current assets	593,755	458,573
Properties and equipment, net	7,293,355	4,814,865
Fair value of derivatives	25,562	15,177
Other assets	70,093	48,051
Total Assets	$ 7,982,765	$ 5,336,666
Liabilities and Stockholders' Equity		
Liabilities		
Current liabilities:		
Accounts payable	$ 244,406	$ 127,891
Production tax liability	244,737	99,583
Fair value of derivatives	274,218	304,870
Funds held for distribution	539,094	285,861
Accrued interest payable	11,655	10,482
Other accrued expenses	106,082	91,409
Total current liabilities	1,420,192	920,096
Long-term debt	1,314,010	942,084
Asset retirement obligations	171,665	127,526
Fair value of derivatives	53,600	95,561
Deferred income taxes	507,683	26,383
Other liabilities	532,870	314,769
Total liabilities	4,000,020	2,426,419
Commitments and contingent liabilities		
Stockholders' equity		
Common shares - par value $0.01 per share, 150,000,000 authorized, 89,224,353 and 96,468,071 issued as of December 31, 2022 and 2021, respectively	892	965
Additional paid-in capital	2,823,364	3,161,941
Retained earnings (accumulated deficit)	1,165,816	(249,954)
Treasury shares - at cost, 119,336 and 54,960 as of December 31, 2022 and 2021, respectively	(7,327)	(2,705)
Total stockholders' equity	3,982,745	2,910,247
Total Liabilities and Stockholders' Equity	$ 7,982,765	$ 5,336,666

See accompanying Notes to Consolidated Financial Statements

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

	Year Ended December 31,		
	2022	2021	2020
Revenues			
Crude oil, natural gas and NGLs sales	$ 4,296,681	$ 2,552,558	$ 1,152,555
Commodity price risk management gain (loss), net	(463,611)	(701,456)	180,270
Other income	12,663	4,808	6,401
Total revenues	3,845,733	1,855,910	1,339,226
Costs, expenses and other			
Lease operating expense	262,986	180,659	161,346
Production taxes	311,778	165,209	59,368
Transportation, gathering and processing expense	124,577	100,403	77,835
Exploration, geologic and geophysical expense	13,079	1,064	1,376
General and administrative expense	156,276	127,733	161,087
Depreciation, depletion and amortization	749,657	635,184	619,739
Accretion of asset retirement obligations	13,408	12,086	10,072
Impairment of properties and equipment	6,762	402	882,393
Loss (gain) on sale of properties and equipment	212	(912)	(724)
Other expense	—	2,490	10,272
Total costs, expenses and other	1,638,735	1,224,318	1,982,764
Income (loss) from operations	2,206,998	631,592	(643,538)
Interest expense, net	(64,734)	(82,698)	(88,684)
Gain on bargain purchase	90,057	—	—
Income (loss) before income taxes	2,232,321	548,894	(732,222)
Income tax benefit (expense)	(454,200)	(26,583)	7,902
Net income (loss)	$ 1,778,121	$ 522,311	$ (724,320)
Earnings (loss) per share			
Basic	$ 18.76	$ 5.30	$ (7.37)
Diluted	18.49	5.22	(7.37)
Weighted average common shares outstanding			
Basic	94,796	98,546	98,251
Diluted	96,174	100,154	98,251

See accompanying Notes to Consolidated Financial Statements

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

	Year Ended December 31,		
	2022	2021	2020
Cash flows from operating activities:			
Net income (loss)	$ 1,778,121	$ 522,311	$ (724,320)
Adjustments to net income (loss) to reconcile to net cash from operating activities:			
Net change in fair value of unsettled commodity derivatives	(416,278)	291,268	99,001
Depreciation, depletion and amortization	749,657	635,184	619,739
Impairment of properties and equipment	6,762	402	882,393
Exploratory dry hole costs	11,970	—	—
Accretion of asset retirement obligations	13,408	12,086	10,072
Non-cash stock-based compensation	26,846	23,023	22,200
Amortization and write-off of debt discount, premium and issuance costs	5,436	13,468	16,772
Loss from extinguishment of debt	—	6,927	—
Deferred income taxes	452,900	26,383	(6,530)
Gain on bargain purchase	(90,057)	—	—
Other	(374)	1,539	2,280
Changes in assets and liabilities:			
Accounts receivable	19,228	(153,717)	139,664
Other assets	16,364	24,678	(5,341)
Production tax liability	191,175	41,381	(50,803)
Accounts payable and accrued expenses	(44,677)	40,183	(66,183)
Funds held for distribution	80,670	108,729	(23,621)
Asset retirement obligations	(19,880)	(28,595)	(27,491)
Other liabilities	(8,947)	(17,454)	(17,753)
Net cash from operating activities	2,772,324	1,547,796	870,079
Cash flows from investing activities:			
Capital expenditures for development of crude oil and natural gas properties	(1,069,543)	(583,108)	(550,964)
Capital expenditures for midstream assets	(10,069)	—	—
Capital expenditures for other properties and equipment	(18,159)	(894)	(1,634)
Cash paid for acquisition of an exploration and production business	(1,068,241)	—	(139,812)
Proceeds from sale of properties and equipment	717	5,073	1,641
Proceeds from divestitures	15,779	125	3,610
Net cash from investing activities	(2,149,516)	(578,804)	(687,159)
Cash flows from financing activities:			
Proceeds from revolving credit facility and other borrowings	2,683,200	802,800	1,799,350
Repayment of revolving credit facility and other borrowings	(2,313,200)	(970,800)	(1,635,350)
Proceeds from senior notes	—	—	148,500
Redemption of senior notes	—	(308,584)	(452,153)
Repayment of convertible notes	—	(200,000)	—
Payment of debt issuance costs	(101)	(13,066)	(6,538)
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	(18,105)	(6,038)	(9,345)
Purchase of treasury shares under stock repurchase program	(818,325)	(156,795)	(23,819)
Dividends paid	(181,573)	(83,615)	—
Principal payments under financing lease obligations	(2,039)	(1,688)	(1,905)
Net cash from financing activities	(650,143)	(937,786)	(181,260)
Net change in cash and cash equivalents	(27,335)	31,206	1,660
Cash and cash equivalents, beginning of year	33,829	2,623	963
Cash and cash equivalents, end of year	$ 6,494	$ 33,829	$ 2,623

See accompanying Notes to Consolidated Financial Statements

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

	Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount		
Balance at January 1, 2020	61,652	$ 617	$2,384,309	(35)	$ (1,474)	$ (47,945)	$ 2,335,507
Net income (loss)	—	—	—	—	—	(724,320)	(724,320)
Issuance pursuant to acquisition	39,182	391	1,014,921	—	—	—	1,015,312
Stock-based compensation	530	5	19,738	—	2,457	—	22,200
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(457)	(9,345)	—	(9,345)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(339)	(3)	(7,407)	339	7,413	—	3
Retirement of treasury shares	(1,266)	(12)	(23,807)	1,266	23,819	—	—
Issuance of treasury shares	—	—	—	115	—	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(1,266)	(23,819)	—	(23,819)
Balance at December 31, 2020	99,759	998	3,387,754	(38)	(949)	(772,265)	2,615,538
Net income (loss)	—	—	—	—	—	522,311	522,311
Stock-based compensation	531	5	20,831	—	2,187	—	23,023
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(181)	(6,038)	—	(6,038)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(117)	(1)	(4,156)	117	4,157	—	—
Retirement of treasury shares	(3,705)	(37)	(157,058)	3,711	157,401	—	306
Issuance of treasury shares	—	—	—	89	—	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(3,753)	(159,463)	—	(159,463)
Dividends declared ($0.86 per share)	—	—	(85,430)	—	—	—	(85,430)
Balance at December 31, 2021	96,468	965	3,161,941	(55)	(2,705)	(249,954)	2,910,247
Net income (loss)	—	—	—	—	—	1,778,121	1,778,121
Issuance pursuant to acquisition	4,007	40	293,274	—	—	—	293,314
Stock-based compensation	1,038	10	22,673	—	4,163	—	26,846
Purchase of treasury shares for employee stock-based compensation tax withholding obligations	—	—	—	(283)	(18,105)	—	(18,105)
Retirement of treasury shares for employee stock-based compensation tax withholding obligations	(170)	(2)	(11,199)	170	11,684	(483)	—
Retirement of treasury shares	(12,119)	(121)	(584,199)	12,119	820,993	(236,673)	—
Issuance of treasury shares	—	—	—	75	—	—	—
Purchase of treasury shares under stock repurchase program	—	—	—	(12,145)	(823,357)	—	(823,357)
Dividends declared ($1.95 per share)	—	—	(59,126)	—	—	(125,195)	(184,321)
Balance at December 31, 2022	89,224	$ 892	$2,823,364	(119)	$ (7,327)	$ 1,165,816	$ 3,982,745

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 horizontal Wolfcamp zones. As of December 31, 2022, we owned an interest in approximately 4,100 gross productive 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 in consolidation.

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 on 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 impairment assessment; 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, 2022 and 2021. 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, realized gains and losses from the settlement of commodity derivatives and unrealized gains and losses from changes in the fair value of remaining unsettled commodity derivatives are presented as a component of revenues 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, adjusted as necessary, 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 on the consolidated statements of operations.

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. 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 capital and 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. We evaluate significant unproved properties for impairment based on future drilling plans and expected future lease expirations, primarily in areas where we have no development plans.

Other Property and Equipment. Other property and equipment such as vehicles, facilities, midstream pipeline, office furniture and equipment, buildings, computer hardware and software and leasehold improvements 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. Leasehold improvements are depreciated over the lesser of their useful lives or the term of the lease. Total depreciation expense related to other property and equipment was $7.8 million, $7.7 million and $8.7 million for the years ended December 31, 2022, 2021 and 2020, 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.

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. We capitalize interest on expenditures made in connection with exploration and development projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring unevaluated properties to its intended use. Interest capitalized may not exceed gross interest expense for the period. Capitalized interest totaled $21.5 million, $17.8 million and $19.7 million during the year ended December 31, 2022, 2021 and 2020, respectively.

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.

We recognize 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. Our 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 and recognized as 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 (presented as part of properties and equipment). 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 our 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, 2022, 2021 and 2020, 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 our commodity product has been transferred to the purchasers 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, we utilized the practical expedient in ASC Topic 606 which states that we are 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 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).

NOTE 3 - BUSINESS COMBINATION

On May 6, 2022, we completed the acquisition of Great Western Petroleum, LLC (“Great Western”) for approximately $1.4 billion, inclusive of Great Western’s net debt (the “Great Western Acquisition”). Great Western was an independent oil and gas company focused on the exploration, production and development of crude oil and natural gas in the Wattenberg Field of Colorado. The consideration paid included $542.5 million in cash and approximately 4.0 million shares of our common stock, valued at $293.3 million on the acquisition date. In addition, we paid off the Great Western secured credit facility totaling $235.8 million and irrevocably deposited $361.2 million on Great Western’s behalf to pay and discharge on May 20, 2022 Great Western’s 12 percent senior secured notes due 2025, inclusive of unpaid accrued interest and a premium for early termination. The cash portion of the purchase price and the termination of Great Western’s debt were funded through a combination of cash on hand and availability under our revolving credit facility.

Purchase Price Allocation

The Great Western Acquisition has been accounted for using the acquisition method under Accounting Standards Codification (“ASC”) 805, *Business Combinations*, with PDC being treated as the accounting acquirer. Accordingly, we conducted assessments of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values, while transaction and integration costs associated with the acquisition were expensed as incurred.

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 Great Western Acquisition:

		(in thousands, except share and per share data)
Consideration:		
Cash	$	542,500
Retirement of Great Western's credit facility		235,822
Extinguishment of Great Western's secured senior notes		361,231
Total cash consideration	$	1,139,553
Common stock issued		4,007,018
Fair value of PDC common stock on May 6, 2022	$	73.20
Total fair value of common stock issued		293,314
Total consideration	$	1,432,867
Assets acquired:		
Cash	$	63,183
Accounts receivable		164,026
Other current assets		3,129
Properties and equipment, net - proved		2,091,301
Properties and equipment, net - other		7,035
Other noncurrent assets		20,345
Total assets acquired	$	2,349,019
Liabilities assumed:		
Accounts payable	$	(119,142)
Production tax liability		(110,940)
Funds held for distribution		(170,708)
Other current liabilities		(19,203)
Fair value of derivatives		(319,600)
Asset retirement obligations		(25,300)
Deferred tax liabilities		(28,400)
Other liabilities		(32,802)
Total liabilities assumed	$	(826,095)
Total identifiable net assets acquired	$	1,522,924
Gain on bargain purchase		90,057
Purchase price consideration	$	1,432,867

Determining the fair values of the assets and liabilities of Great Western requires judgement and certain assumptions to be made, the most significant of these being related to the valuation of crude oil and natural gas properties. The majority of the 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 reserve volumes, future operating and development costs, future commodity prices and a market-based weighted-average cost of capital rate of 14.25 percent. These inputs require significant judgments and estimates by management at the time of the valuation. The fair value of derivative instruments was based on observable inputs, including forward commodity-price curves which are considered Level 2 inputs, and based on volatility factors which are considered Level 3 inputs. We completed our purchase price allocation analysis as of December 31, 2022, with immaterial adjustments made to the previous allocation.

ASC 805, *Business Combinations*, requires that any excess of purchase price over the fair value of assets acquired, including identifiable intangibles and liabilities assumed, be recognized as goodwill and any excess of fair value of acquired net assets, including identifiable intangible assets over the acquisition consideration, results in a gain from bargain purchase. Prior to recording a gain, the acquiring entity must reassess whether all assets acquired and assumed liabilities have been identified and recognized and perform re-measurements to verify that the consideration paid, assets acquired and liabilities assumed have been properly valued. The Great Western Acquisition resulted in a gain on bargain purchase due to the estimated fair value of the identifiable net assets acquired exceeding the purchase consideration transferred by $90.1 million and is shown as a gain on bargain purchase on our consolidated statement of operations, net of related income taxes of $28.4 million. Upon completion of our assessment, we concluded that recording a gain on bargain purchase was appropriate and required under ASC 805. The bargain purchase was primarily attributable to the increase in commodity price forecasts from the date we entered into the definitive purchase agreement with Great Western, February 26, 2022, to the closing date of the acquisition, May 6, 2022, when the fair value of crude oil and natural gas reserves acquired were determined. Additionally, the majority of the acquisition consideration was fixed and therefore did not fluctuate as a result of market increases or decreases between the date of entry into the agreement through the closing date.

The results of operations for the Great Western Acquisition since the closing date have been included on our consolidated financial statements for the year ended December 31, 2022 and include approximately $631.0 million of total revenues and $387.8 million of income from operations, respectively. During the year ended December 31, 2022, we recognized total transaction costs of $11.7 million, which are included in general and administrative expense on the consolidated statement of operations.

Pro Forma Information. The following unaudited pro forma financial information represents a summary of the condensed consolidated results of operations for the year ended December 31, 2022 and 2021, assuming the acquisition had been completed as of January 1, 2021. 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.

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) our common stock issued to the owners of Great Western, (ii) the increase in depletion reflecting the relative fair values and production volumes attributable to Great Western's properties and the revision to the depletion rate reflecting the reserve volumes acquired, (iii) adjustments to interest expense as a result of payoff of Great Western's credit facility and secured senior notes, (iv) the adjustment to reflect the gain on bargain purchase, and (v) the estimated tax impacts of the pro forma adjustments. In addition, pro forma earnings were adjusted to exclude acquisition-related costs incurred by us and Great Western totaling approximately $33.6 million for the year ended December 31, 2022, and included the total costs of $33.6 million for the year ended December 31, 2021.

	Year Ended December 31,	
	2022	2021
	(in thousands, except per share data)	
Total revenue	$ 3,897,361	$ 2,277,463
Net income (loss)	1,651,029	563,855
Earnings (loss) per share:		
Basic	$ 17.42	$ 5.50
Diluted	17.17	5.41

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, 2022	2021	2020
		(in thousands)	
Crude oil			
Wattenberg Field	$ 2,154,435	$ 1,275,666	$ 668,948
Delaware Basin	423,784	255,135	147,902
Total	2,578,219	1,530,801	816,850
Natural gas			
Wattenberg Field	870,560	458,870	171,755
Delaware Basin	113,909	60,733	6,997
Total	984,469	519,603	178,752
NGLs			
Wattenberg Field	614,260	428,570	128,126
Delaware Basin	119,733	73,584	28,827
Total	733,993	502,154	156,953
Crude oil, natural gas and NGLs			
Wattenberg Field	3,639,255	2,163,106	968,829
Delaware Basin	657,426	389,452	183,726
Total	$ 4,296,681	$ 2,552,558	$ 1,152,555

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, interest rates, volatility factors and nonperformance risk. Non-performance 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 use our counterparties' valuations to assess reasonableness of our fair value measurement.

Our crude oil and natural gas fixed-price exchanges and basis exchanges are included in Level 2. Our collars are included in 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 dates indicated:

	Consolidated Balance Sheet Line Item	December 31, 2022 Significant Other Observable Inputs (Level 2)	December 31, 2022 Significant Unobservable Inputs (Level 3)	December 31, 2022 Total	December 31, 2021 Significant Other Observable Inputs (Level 2)	December 31, 2021 Significant Unobservable Inputs (Level 3)	December 31, 2021 Total
		(in thousands)					
Derivative assets							
Current	Fair value of derivatives	$ 9,178	$ 22,785	$ 31,963	$ —	$ 17,909	$ 17,909
Non-current	Fair value of derivatives	20,439	5,123	25,562	605	14,572	15,177
Total		$ 29,617	$ 27,908	$ 57,525	$ 605	$ 32,481	$ 33,086
Derivative liabilities							
Current	Fair value of derivatives	$ (214,171)	$ (60,047)	$ (274,218)	$ (230,695)	$ (74,175)	$ (304,870)
Non-current	Fair value of derivatives	(49,749)	(3,851)	(53,600)	(74,715)	(20,846)	(95,561)
Total		$ (263,920)	$ (63,898)	$ (327,818)	$ (305,410)	$ (95,021)	$ (400,431)

The following table presents a reconciliation of our Level 3 commodity derivative assets and liabilities measured at fair value for the periods presented:

	Year Ended December 31, 2022	2021	2020
	(in thousands)		
Fair value of Level 3 instruments, net asset (liability) beginning of period	$ (62,540)	$ (8,427)	$ 8,414
Commodity derivatives acquired from acquisition of business	(22,716)	—	—
Changes in fair value included in consolidated statements of operations line item:			
Commodity price risk management gain (loss), net	(192,694)	(206,109)	37,821
Settlements included in consolidated statements of operations line items:			
Commodity price risk management gain (loss), net	241,960	151,996	(54,662)
Fair value of Level 3 instruments, net asset (liability) end of period	$ (35,990)	$ (62,540)	$ (8,427)
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	$ (31,367)	$ (35,108)	$ —
Total	$ (31,367)	$ (35,108)	$ —

The significant unobservable input used in the fair value measurement of our derivative contracts is the implied volatility curve. 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 measure fair value using inputs that are not observable in the market, and are 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. The most significant fair value determinations for non-financial assets and liabilities are related to crude oil and gas properties acquired. See *Note 3 - Business Combination* for additional information.

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 elected not 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 as of the dates indicated:

		December 31,			
		2022		2021	
	Nominal Interest	Estimated Fair Value	Percent of Par	Estimated Fair Value	Percent of Par
		(in millions)		*(in millions)*	
2024 Senior Notes	6.125 %	198.4	99.2 %	202.8	101.4 %
2026 Senior Notes	5.75 %	716.0	95.5 %	775.5	103.4 %

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 crude oil and natural 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, 2022, we had derivative instruments in place for a portion of our anticipated production in 2023 through 2025. 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, 2022 and 2021, 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.

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 for the periods presented:

Consolidated Statements of Operations Line Item	Year Ended December 31, 2022	2021	2020
		(in thousands)	
Commodity price risk management gain (loss), net			
Net settlements	$ (879,889)	$ (410,188)	$ 279,271
Net change in fair value of unsettled derivatives	416,278	(291,268)	(99,001)
Total commodity price risk management gain (loss), net	$ (463,611)	$ (701,456)	$ 180,270

Commodity Derivative Contracts. As of December 31, 2022, we had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is presented:

	Collars			Fixed-Price Swaps		
		Weighted Average Contract Price				
Commodity/ Index/ Maturity Period	**Quantity** *(Crude oil - MBbls Natural Gas - BBtu)*	**Floors**	**Ceilings**	**Quantity** *(Crude Oil - MBbls Gas and Basis- BBtu)*	**Weighted Average Contract Price**	**Fair Value December 31, 2022** *(in thousands)*
Crude Oil						
NYMEX						
2023	5,937	$ 61.27	$ 83.11	9,804	$ 66.42	$ (156,820)
2024	825	65.91	89.58	6,126	70.59	(17,042)
2025	—	—	—	2,640	75.10	12,262
Total Crude Oil	6,762			18,570		(161,600)
Natural Gas						
NYMEX						
2023	26,864	3.48	6.03	41,825	3.05	(51,443)
2024	—	—	—	26,160	3.54	(17,511)
2025	—	—	—	6,225	4.87	2,640
	26,864			74,210		(66,314)
CIG						
2023	—	—	—	8,760	3.39	(7,657)
2025	—	—	—	4,800	3.10	(4,370)
	—			13,560		(12,027)
Total Natural Gas	26,864			87,770		(78,341)
Basis Protection - Natural Gas						
CIG						
2023	—	—	—	67,742	(0.26)	(26,335)
2024	—	—	—	26,160	(0.39)	(3,329)
2025	—	—	—	6,225	(0.37)	(688)
Total Basis Protection - Natural Gas	—			100,127		(30,352)
Commodity Derivatives Fair Value						$ (270,293)

Effect of Derivative Instruments on the Consolidated Balance Sheet. The balance sheet line items and fair value amounts of our derivative instruments are disclosed in *Note 5 - Fair Value Measurements*.

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:

	Total Gross Amount Presented on the Balance Sheet	Effect of Master Netting Agreements	Total Net Amount
As of December 31, 2022		*(in thousands)*	
Derivative asset instruments, at fair value	$ 57,525	$ (57,525)	$ —
Derivative liability instruments, at fair value	$ 327,818	$ (57,525)	$ 270,293
As of December 31, 2021			
Derivative asset instruments, at fair value	$ 33,086	$ (33,086)	$ —
Derivative liability instruments, at fair value	$ 400,431	$ (33,086)	$ 367,345

Derivative Counterparties. Our commodity derivative instruments expose us to the risk of non-performance by our counterparties. We 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 non-performance of our current counterparties on the fair value of our derivative instruments is not significant at December 31, 2022; however, this determination may change.

NOTE 7 - PROPERTIES AND EQUIPMENT, NET

The following table presents the components of properties and equipment, net of accumulated depreciation, depletion and amortization ("DD&A"), as of the dates indicated:

	December 31, 2022	December 31, 2021
	(in thousands)	
Properties and equipment, net:		
Crude oil and natural gas properties		
Proved	$ 11,324,756	$ 8,310,018
Unproved	156,418	306,181
Total crude oil and natural gas properties	11,481,174	8,616,199
Equipment and other	72,151	63,099
Land and buildings	25,406	19,928
Construction in progress	716,302	371,968
Properties and equipment, at cost	12,295,033	9,071,194
Accumulated DD&A	(5,001,678)	(4,256,329)
Properties and equipment, net	$ 7,293,355	$ 4,814,865

Suspended Well Costs. The following table presents the changes in capitalized exploratory well cost pending determination of proved reserves and included in properties and equipment for the periods presented:

	Year Ended December 31,		
	2022	2021	2020
	(in thousands, except for number of wells)		
Beginning balance	$ —	$ 7,459	$ 16,078
Additions to capitalized exploratory well costs pending the determination of proved reserves	—	5,902	11,770
Reclassifications to proved properties	—	(13,361)	(20,389)
Ending balance	$ —	$ —	$ 7,459
Number of wells pending determination at period-end	—	—	2

During the year ended December 31, 2022, we drilled and turned-in-line an exploratory well in the Delaware Basin that did not yield sufficient projected returns for it to be deemed economically viable. Therefore, in 2022, we expensed the associated lease costs and related infrastructure assets of the exploratory dry hole at a cost of $12.0 million, an amount which was recognized on the consolidated statements of operations as exploration, geologic and geophysical expense.

As of December 31, 2020, our net capitalized exploratory well costs that had been capitalized for a period greater than one year was $7.5 million, which comprised the entire balance of our suspended well costs and related to two gross suspended wells associated with two projects. During the year ended December 31, 2021, both exploratory wells were determined to be successful producing wells and were reclassified into proved properties. We had no capitalized exploratory well costs pending determination as of December 31, 2022 and 2021.

Impairment of Oil and Gas Properties. The following table presents impairment charges recorded for properties and equipment for the periods presented:

	Year Ended December 31,		
	2022	2021	2020
	(in thousands)		
Impairment of proved and unproved properties	$ 6,762	$ 402	$ 881,238
Impairment of infrastructure and other	—	—	1,155
Total impairment of properties and equipment	$ 6,762	$ 402	$ 882,393

Oil and Gas Properties.

In the first quarter of 2020, the significant decline in crude oil prices in addition to the ongoing effects of the COVID-19 pandemic were 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. During the years ended December 31, 2022 and 2021, there were no significant impairments recognized.

Proved Properties. Of the total impairment expense recognized in 2020, 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 future production 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.

Unproved Properties. We recognized approximately $127.3 million of impairment charges for our unproved properties in the Delaware Basin in 2020. These impairment charges were recognized based on the fair value of the properties, a Level 3 input. The fair value was estimated based on a review of our drilling plans, estimated future cash flows for probable well locations and expected lease expirations, primarily in areas where we had no development plans.

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, 2022	December 31, 2021
	(in thousands)	
Crude oil, natural gas and NGLs sales	$ 491,327	$ 368,991
Joint interest billings	46,633	24,860
Other	13,796	10,809
Allowance for doubtful accounts	(5,445)	(6,055)
Accounts receivable, net	$ 546,311	$ 398,605

The Company's accounts receivable consist mainly of receivables from (i) crude oil, natural gas and NGLs purchasers, (ii) joint interest owners in the properties we operate and (iii) derivative counterparties. Most payments for production are received within two months after the production date. For receivables from joint interest owners, we typically have 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.

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 in our operating areas. The following major customers accounted for 10 percent or more of our total crude oil, natural gas, and NGLs sales for at least one of the periods presented:

	Year Ended December 31, 2022	2021	2020
Major customer #1	27 %	32 %	31 %
Major customer #2	9 %	9 %	16 %
Major customer #3	7 %	11 %	13 %
Major customer #4	5 %	10 %	17 %

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

	December 31, 2022	December 31, 2021
	(in thousands)	
Employee benefits	$ 29,288	$ 29,319
Asset retirement obligations	25,986	32,146
Environmental expenses	25,666	11,942
Operating and finance leases	5,987	7,197
Other	19,155	10,805
Other accrued expenses	$ 106,082	$ 91,409

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

	December 31,	
	2022	2021
	(in thousands)	
Deferred midstream gathering credits	$ 145,937	$ 159,788
Production taxes	315,758	131,865
Operating and finance leases	41,815	6,274
Other	29,360	16,842
Other liabilities	$ 532,870	$ 314,769

Deferred Midstream Gathering Credits. In 2019, we entered into agreements pursuant to which we dedicated the gathering of some 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.

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,	
	2022	2021
	(in thousands)	
Transportation, gathering and processing expense	$ 11,037	$ 7,317
Lease operating expense	3,753	2,422

NOTE 9 - LONG-TERM DEBT

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $6.0 million and $7.9 million as of December 31, 2022 and December 31, 2021, respectively, consists of the following:

	December 31,	
	2022	2021
	(in thousands)	
Revolving credit facility due November 2026	$ 370,000	$ —
6.125% Senior Notes due September 2024	199,163	198,674
5.75% Senior Notes due May 2026	744,847	743,410
Total debt, net of unamortized discount, premium and debt issuance costs	$ 1,314,010	$ 942,084

Revolving Credit Facility

In November 2021, we entered into a Fifth Amended and Restated Credit Agreement (the "Restated Credit Agreement"), which provides for a maximum credit amount of $2.5 billion, subject to certain limitations, an initial borrowing base of $2.4 billion and an elected commitment of $1.5 billion. The Restated Credit Agreement matures on the earlier to occur of (i) the end of the five year term on November 2, 2026 or (ii) the date that is 91 days prior to the scheduled maturity of the 2026 Senior Notes if the aggregate outstanding principal amount of those notes exceeds $500 million and our commitment utilization exceeds 50%. In the semi-annual redetermination that occurred in 2022, the borrowing base increased from $3.0 billion to $3.5 billion as a result of the reserves acquired in the Great Western Acquisition; however, we maintained our elected commitment amount of $1.5 billion.

The revolving credit facility is available for working capital requirements, capital investments, acquisitions, to support letters of credit and for general business 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 Restated Credit Agreement includes an investment grade period election pursuant to which we have an option to remove our borrowing base limitations and terminate the liens securing the Restated Credit Agreement when certain debt ratings are achieved.

As of December 31, 2022, we had a borrowing base of $3.5 billion, an elected commitment of $1.5 billion and availability under our revolving credit facility of $1.1 billion, net of $20.4 million of letters of credit outstanding.

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 Secured Overnight Financing Rate (“SOFR”) for one month, plus a premium) or, at our election, a rate equal to SOFR 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, 2022, the applicable interest margin is 0.75 percent for the alternate base rate option or 1.75 percent for the SOFR option, and the unused commitment fee is 0.375 percent. Principal payments are generally not required until the maturity date of the revolving credit facility, unless the borrowing base falls below the outstanding balance. The Restated Credit Agreement also includes the ability to add certain sustainability-linked key performance indicators to be agreed upon between us, the administrative agent and a majority of the lenders and that may impact the applicable margin and commitment fee rate.

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 a minimum current ratio of 1.0:1.0 and a maximum leverage ratio of 3.5:1.0; (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, 2022, we were in compliance with all covenants related to our revolving credit facility.

As of December 31, 2022 and 2021, debt issuance costs related to our revolving credit facility were $13.5 million and $16.9 million, respectively, and are included in other assets on our consolidated balance sheets.

Senior Notes

The following table summarizes the face values, interest rates, maturity dates, semi-annual interest payment dates, and optional redemption periods related to our outstanding senior note obligations as of December 31, 2022:

	2024 Senior Notes	2026 Senior Notes
Outstanding principal amounts (in thousands)	$ 200,000	$ 750,000
Interest rate	6.125 %	5.75 %
Maturity date	September 15, 2024	May 15, 2026
Interest payment dates	March 15, September 15	May 15, November 15
Redemption periods (1)	September 15, 2022	May 15, 2024

(1) At any time prior to the indicated dates, we have the option to redeem all or a portion of our senior notes of the applicable series at the redemption amounts specified in the respective senior note indenture plus accrued and unpaid interest to the date of redemption. On or after the indicated dates, we may redeem all or a portion of the senior notes at a redemption amount equal to 100% of the principal amount of the senior notes being redeemed plus accrued and unpaid interest to the date of redemption.

The 2024 Senior Notes and the 2026 Senior Notes (collectively, 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 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 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 accrued and unpaid interest to the date of purchase.

The indentures governing the Senior Notes contain covenants and restricted payment provisions 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, 2022, we were in compliance with all covenants and all restricted payment provisions related to our Senior Notes.

Our wholly-owned subsidiaries PDC Permian, Inc. and Pioneer Water Pipeline LLC (acquired in connection with the Great Western Acquisition), are each a guarantor of our obligations under our Senior Notes and our credit facility.

NOTE 10 - LEASES

We have operating leases for office space and well equipment, and finance leases for vehicles. Our leases have remaining lease terms ranging from one month to ten years. The vehicle leases include an option to renew on a month-to-month basis after the primary term. 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 presented:

	Year Ended December 31,	
	2022	2021
	(in thousands)	
Operating lease costs [1]	$ 6,743	$ 6,125
Finance lease costs:		
Amortization of ROU assets	2,100	1,752
Interest on lease liabilities	270	164
Total finance lease costs	2,370	1,916
Short-term lease costs [1]	338,404	203,361
Total lease costs	$ 347,517	$ 211,402

(1) The lease costs presented in the table above represent the total gross costs we incur, which are not comparable to our 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 assets 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 the dates indicated:

		December 31,	
Leases	**Consolidated Balance Sheet Line Item**	**2022**	**2021**
		(in thousands)	
Operating lease ROU assets	Other assets	$ 19,577	$ 7,630
Finance lease ROU assets	Properties and equipment, net	6,184	3,483
Total ROU assets		$ 25,761	$ 11,113
Operating lease obligation - short-term	Other accrued expenses	$ 3,825	$ 5,937
Operating lease obligation - long-term	Other liabilities	37,720	4,044
Finance lease obligation - short-term	Other accrued expenses	2,162	1,260
Finance lease obligation - long-term	Other liabilities	4,095	2,230
Total lease liabilities		$ 47,802	$ 13,471

Leases	Consolidated Balance Sheet Line Item	December 31, 2022	December 31, 2021
		(in thousands)	
Weighted average remaining lease term (years)		7.9	2.8
Weighted average discount rate		5.1 %	4.8 %

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, 2022 consist of the following:

	Operating Leases	Finance Leases	Total
		(in thousands)	
2023	$ 4,063	$ 2,404	$ 6,467
2024	3,101	1,891	4,992
2025	6,682	1,698	8,380
2026	6,754	649	7,403
2027	5,821	73	5,894
Thereafter	27,512	—	27,512
Total lease payments	53,933	6,715	60,648
Less: Interest and discount	(12,388)	(458)	(12,846)
Present value of lease liabilities	$ 41,545	$ 6,257	$ 47,802

In September 2022, we entered into a three-year drilling rig agreement with total gross lease payments of approximately $34 million which we expect to commence and be recognized on our balance sheet in the first quarter of 2023.

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 for the periods presented:

	Year Ended December 31, 2022	Year Ended December 31, 2021
	(in thousands)	
Beginning balance	$ 159,672	$ 166,570
Obligations incurred with development activities and other	5,332	4,750
Obligations incurred with acquisition	25,300	—
Accretion expense	13,408	12,086
Revisions in estimated cash flows	19,606	10,609
Obligations discharged with asset retirements and divestitures	(25,667)	(34,343)
Asset retirement obligations at end of period	197,651	159,672
Current portion[(1)]	(25,986)	(32,146)
Long-term portion	$ 171,665	$ 127,526

(1) The current portion of the asset retirement obligation is included in other accrued expenses on our consolidated balance sheets.

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 the time that the obligation is incurred. 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.

NOTE 12 - COMMITMENTS AND CONTINGENCIES

The following table presents our firm transportation, sales and processing, water delivery and disposal and purchase commitments:

	Year Ending December 31,						
(in thousands)	2023	2024	2025	2026	2027	Thereafter	Total
Firm transportation	$ 96,567	$ 64,403	$ 49,187	$ 36,692	$ 10,388	$ 28,364	$ 285,601
Gas gathering and processing agreements	117,828	117,509	101,553	61,633	35,608	43,801	477,932
	$ 214,395	$ 181,912	$ 150,740	$ 98,325	$ 45,996	$ 72,165	$ 763,533

Firm Transportation and Processing Agreements. We enter into certain contracts that provide firm transportation and processing on pipeline systems through which we transport or sell crude oil and natural gas. Under certain of these agreements, we are obligated to ship minimum daily quantities of crude oil or natural gas or pay for any deficiencies at a specified rate or incremental charges. 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. 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. Our consolidated statements of operations reflect our share of these firm transportation and processing costs. Payments related to our long-term transportation and processing agreements, net of interests, were $64.1 million, $31.3 million, and $21.4 million for the years ended December 31, 2022, 2021, and 2020, respectively. For the years ended December 31, 2022 and 2021, we did not incur material transportation reservation charges under these agreements.

Gas Gathering and Processing Agreements. We entered into certain long-term gas gathering and processing agreements pursuant to which we are obligated to deliver minimum daily quantities of natural gas to certain gas gathering and processing plants for processing or pay for any deficiencies at a specified rate or margin. If we ceased operations in the areas subject to these agreements at December 31, 2022, the total deficiencies required to be paid by the Company under these agreements are reflected in the table presented above. Our consolidated statements of operations reflect our share of these processing costs.

Firm sales agreement. As of December 31, 2022 we had a firm sales agreement with an integrated marketing company for our crude oil production in the Delaware Basin through 2023. 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. This agreement does not require physical delivery of the minimum volumes of crude oil over the contractual term. However, if we do not sell and deliver at least the minimum contract volume pursuant to the agreement, we are required to pay transportation reservation charges related to the undelivered volume. For the years ended December 31, 2022 and 2021, we did not incur material transportation reservation charges under this agreement.

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.

NOTE 13 - COMMON STOCK

Stock-Based Compensation Plans

2018 Equity Incentive Plan. In 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”) to 7,050,000 shares. The 2018 Plan expires in March 2028. The capital stock available for issuance under the 2018 Plan consists of 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, such shares remain available for issuance. Any shares withheld for taxes cannot be recycled under this plan. Awards may be issued in the form of stock 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 our board of directors (the "Compensation Committee"), with a minimum one-year vesting period applicable to most awards. With regard to SARs and stock options, awards have a maximum exercisable period of ten years. As of December 31, 2022, there were 3,840,404 shares available for grant under the 2018 Plan.

2010 Long-Term Equity Compensation Plan. Our Amended and Restated 2010 Long-Term Equity Compensation Plan, approved 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, 2022, there were 245,156 shares available for grant under the 2010 Plan.

2015 SRC Equity Incentive Plan. Pursuant to the closing of the SRC Acquisition, SRC granted PSUs to certain SRC executives (the "SRC PSUs") under the 2015 SRC Equity Incentive Plan (the "2015 SRC Plan"). The SRC PSUs were converted into 155,928 PDC PSUs and remained subject to the same terms and conditions (including performance-vesting terms) that applied immediately prior to the closing of the SRC Acquisition. As of December 31, 2021, all converted SRC PSUs vested and in 2022, the 2015 SRC Plan was closed and retired.

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,		
	2022	2021	2020
		(in thousands)	
General and administrative expense	$ 25,257	$ 21,830	$ 21,182
Lease operating expense	1,589	1,193	1,018
Total stock-based compensation expense	$ 26,846	$ 23,023	$ 22,200

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 of these time-based RSUs is based on the closing market price of our common stock on the grant date and is 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 to eligible employees, including executive officers, during the year ended December 31, 2022:

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at beginning of period	1,165,187	$ 25.33
Granted	363,395	70.01
Vested	(581,343)	26.15
Forfeited	(50,728)	40.58
Non-vested at end of period	896,511	42.05

The weighted average grant-date fair value of restricted stock units was $70.01, $33.64 and $11.98 for the years ended December 31, 2022, 2021 and 2020, respectively. The total grant-date fair value of restricted stock units that vested for the years ended December 31, 2022, 2021 and 2020 was $15.2 million, $13.6 million and $20.4 million, respectively. Total compensation cost related to non-vested time-based awards and not yet recognized on the consolidated statements of operations as of December 31, 2022 was $24.7 million. This cost is expected to be recognized over a weighted average period of 1.3 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 102,098 market-based PSUs to our executive officers during 2022. 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, 2024, 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, as well as that of our peer group.

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,		
	2022	2021	2020
Expected term of award (in years)	2.9	3.0	3.0
Risk-free interest rate	1.7%	0.2%	1.4%
Expected volatility	86.3%	84.6%	46.6%
Weighted average grant-date fair value per share	$107.85	$54.01	$33.52

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 during the year ended December 31, 2022:

	Shares	Weighted Average Grant-Date Fair Value per Share
Non-vested at December 31, 2021	439,229	$ 43.21
Granted	102,098	107.85
Granted for performance multiple[(1)]	347,363	33.52
Vested	(578,937)	33.52
Non-vested at December 31, 2022	309,753	71.76

(1) Upon completion of the performance period for the PSUs granted in 2020, a performance multiple of 250% was applied to each of the grants resulting in additional grants of PSUs in December 2022.

The total grant-date fair value of performance stock units that vested in the years ended December 31, 2022, 2021 and 2020 was $19.4 million, $11.6 million and $4.7 million, respectively. Total compensation cost related to non-vested market-based awards not yet recognized on the consolidated statements of operations as of December 31, 2022 was $11.6 million. This cost is expected to be recognized over a weighted average period of 1.3 years.

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 our board of directors from time to time. Through December 31, 2022, no shares of preferred stock have been issued.

Stock Repurchase Program

In 2019, our board of directors approved a program pursuant to which we may acquire shares of our common stock from time to time. At December 31, 2021, $187.3 million of the approved $525.0 million remained available for repurchase under the stock repurchase program. In February 2022, our board of directors approved a new stock repurchase program that reset the total repurchase value to $1.25 billion. The stock repurchase program does not require any specific number of shares to be acquired and can be modified or discontinued by our board of directors at any time. Repurchases under the program can be made in open markets at our discretion and in compliance with safe harbor provisions, or in privately negotiated transactions. Pursuant to the program, we repurchased 12.1 million and 3.8 million shares of outstanding common stock at a cost of $823.4 million and $159.5 million during the years ended December 31, 2022 and 2021, respectively. As of December 31, 2022, $454.7 million remained available under the program for repurchases of our outstanding common stock. In February 2023, our board of directors approved a $750 million increase in the size of our stock repurchase program.

Dividends

In the second quarter of 2021, our board of directors approved the declaration and payment of quarterly cash dividends of common stock. For the years ended December 31, 2022 and 2021, our dividends declared totaled $1.95 per share of outstanding common stock or $184.3 million and $0.86 per share of outstanding common stock or $83.6 million, respectively. All RSUs and PSUs receive a dividend equivalent per unit, recognized as a liability included in other liabilities on our consolidated balance sheets, until the recipients receive the equivalents upon vesting. Dividends declared were recorded as a reduction of retained earnings, however, if there were no retained earnings as of the date of declaration, dividends declared were recorded as a reduction of additional paid-in capital. Future dividend payments must be approved by our board of directors and will depend on our liquidity, financial requirements, and other factors considered relevant by our board. In February 2023, our board of directors approved an increase in the quarterly base dividend from $0.35 to $0.40 per share.

NOTE 14 - INCOME TAXES

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

	Year Ended December 31,		
	2022	2021	2020
		(in thousands)	
Current:			
Federal	$ (400)	$ —	$ 1,592
State	(900)	(200)	(220)
Total current income tax benefit	(1,300)	(200)	1,372
Deferred:			
Federal	(385,300)	(23,790)	5,460
State	(67,600)	(2,593)	1,070
Total deferred income tax (expense) benefit	(452,900)	(26,383)	6,530
Income tax (expense) benefit	$ (454,200)	$ (26,583)	$ 7,902

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

	Year Ended December 31,		
	2022	2021	2020
Federal statutory tax rate	21.0 %	21.0 %	21.0 %
State income tax, net	2.4	3.2	3.0
Change in valuation allowance	(2.0)	(19.8)	(22.1)
Other	(1.1)	0.4	(0.8)
Effective tax rate	20.3 %	4.8 %	1.1 %

The effective income tax rates for 2022, 2021 and 2020 were 20.3 percent, 4.8 percent and 1.1 percent on the respective pre-tax income or loss. The effective tax rates differ from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21 percent to the pre-tax income or loss due to state income taxes and changes in the valuation allowance against our deferred income tax asset.

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,	
	2022	2021
	(in thousands)	
Deferred tax assets:		
Fair value of unsettled commodity derivatives	$ 64,622	$ 88,053
Asset retirement obligations	47,919	38,274
Federal NOL carryforward	84,323	97,555
State NOL and tax credit carryforwards, net	16,190	20,266
Federal tax - credit carryforwards	3,555	3,059
Deferred compensation	7,985	9,949
Other	8,407	8,308
Valuation allowance	—	(56,634)
Total gross deferred tax assets	233,001	208,830
Deferred tax liabilities:		
Properties and equipment	740,684	235,213
Net deferred tax liability	$ 507,683	$ 26,383

We consider whether a portion, or all, of our deferred tax assets ("DTAs") will be realized based on a more likely than not standard of judgment. The ultimate realization of DTAs 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 available taxes in carryback periods, the future reversals of existing taxable temporary differences, tax planning strategies and projected future taxable income in making this assessment. The oil and gas property impairments and cumulative pre-tax losses were key considerations that led us to provide a valuation allowance against our DTAs beginning January 1, 2020 since we previously could not conclude that it is more likely than not that our DTAs will be fully realized in future periods.

As we previously disclosed, we maintained a valuation allowance on our federal deferred tax assets and continued to do so until sufficient positive evidence existed to support a reversal of the allowance. In 2022, continued higher commodity prices increased our income, resulting in the reversal of objective negative evidence of cumulative loss in recent years, and we determined that we had sufficient positive evidence to release the valuation allowance. As a result, we released in full the valuation allowance against our deferred income tax assets of $56.6 million and recognized a corresponding decrease to income tax expense.

As of December 31, 2022, we have estimated net operating loss carryforwards ("NOLs") for federal income tax purposes of $401.5 million, of which $201.3 million was generated before January 1, 2018 and will begin to expire in 2037. In

2020, we acquired a federal NOL of $232.5 million as a component of the SRC Acquisition. This NOL is subject to an annual limitation of $16.1 million, as the acquisition constituted a change of ownership for SRC as defined under Internal Revenue Service ("IRS") Code Section 382.

As of December 31, 2022, we have state NOL carryforwards of $331.2 million that begin to expire in 2029 and state credit carryforwards of $4.5 million that begin to expire in 2023.

Unrecognized tax benefits and related accrued interest and penalties were immaterial for the three-year period ended December 31, 2022. As of December 31, 2022, there is no liability for unrecognized income tax benefits.

We are subject to the following material taxing jurisdictions: U.S., Colorado and Texas. As of December 31, 2022, 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 the NOL is utilized. The statute of limitations has expired for all federal and state returns filed for periods ending before 2017. The IRS has accepted our 2020 and 2021 federal income tax returns with no tax adjustments. We continue to voluntarily participate in the IRS CAP Program. For 2022, we are in the Bridge Phase of the CAP, which means that the IRS will not be examining the 2022 tax year. Participation in the IRS CAP Program has enabled us to have minimal uncertain tax benefits associated with our federal tax return filings. The statutes of limitations for most of our state tax jurisdictions are open for tax years after 2017.

In August 2022, the Inflation Reduction Act ("IRA") was signed into law. The IRA includes implementation of a new alternative minimum tax, an excise tax on stock buybacks, and significant tax incentives for energy and climate initiatives, among other provisions. The alternative minimum tax and excise tax on stock buyback provisions are effective for tax years beginning after December 31, 2022. We continue to monitor updates to the IRA and the impact to our financial position, results of operations and liquidity. We do not believe it will have a material impact on our stock buyback program or our financial position in 2023, however, we are still assessing the impact for subsequent years.

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 stock-based employee awards, convertible notes (if applicable) 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,		
	2022	2021	2020
		(in thousands)	
Weighted average common shares outstanding - basic	94,796	98,546	98,251
Dilutive effect of:			
RSUs and PSUs	1,352	1,596	—
Other equity-based awards	26	12	—
Weighted average common shares and equivalents outstanding - diluted	96,174	100,154	98,251

We reported a net loss for the year ended December 31, 2020, and as a result, our basic and diluted weighted average common shares outstanding were the same for the period because the effect of the common share equivalents were 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,		
	2022	2021	2020
		(in thousands)	
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:			
RSUs and PSUs	144	28	1,707
Other equity-based awards	32	116	229
Total anti-dilutive common share equivalents	176	144	1,936

NOTE 16 - SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

	Year Ended December 31,		
	2022	2021	2020
		(in thousands)	
Supplemental cash flow information			
Cash payments (receipts) for			
Interest, net of capitalized interest	$ 58,143	$ 66,647	$ 75,506
Income taxes	58	(1,057)	9
Non-cash investing and financing activities			
Change in accounts payable related to capital expenditures	38,384	519	(28,676)
Change in asset retirement obligations, with a corresponding change to crude oil and natural gas properties, net of disposals	21,778	11,673	54,984
Issuance of common stock for acquisition of an exploration and production business	293,314	—	1,009,015
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from operating leases	$ 7,230	$ 7,603	$ 9,246
Operating cash flows from finance leases	254	117	156
Right-of-use assets recognized (derecognized) with offsetting lease liabilities			
Operating leases [(1)]	$ 17,247	$ 1,457	$ 4,305
Finance leases	4,919	2,109	703

(1) Includes $1.5 million operating lease acquired from Great Western.

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 specialists, specifically petroleum engineers, to estimate our crude oil, natural gas and NGLs reserves. As of December 31, 2022, 2021 and 2020 (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)**
2022	$ 93.67	$ 6.36	$ 93.67
2021	66.56	3.60	66.56
2020	39.57	1.99	39.57

(1) Our benchmark indexes 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 Mcf)**	**NGLs (per Bbl)**
2022	$ 94.23	$ 4.82	$ 31.60
2021	65.37	2.85	24.96
2020	37.52	1.26	10.55

(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, 2022.

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SUPPLEMENTAL INFORMATION
(Unaudited)

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, 2020	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
Revisions of previous estimates	22,651	408,540	54,634	145,375
Extensions, discoveries and other additions	528	1,584	168	960
Acquisition of reserves	1,616	24,174	2,469	8,113
Dispositions	—	—	—	—
Production	(22,682)	(175,747)	(19,360)	(71,333)
Proved reserves, December 31, 2021	213,845	2,159,725	240,389	814,188
Revisions of previous estimates	15,607	506,220	74,317	174,294
Extensions, discoveries and other additions	—	—	—	—
Acquisition of reserves	68,064	425,870	57,344	196,387
Dispositions	(10)	(195)	(22)	(65)
Production	(27,486)	(199,362)	(24,325)	(85,038)
Proved reserves, December 31, 2022	270,020	2,892,258	347,703	1,099,766
Proved developed reserves, as of:				
December 31, 2020	86,330	860,877	91,702	321,512
December 31, 2021	97,420	1,088,700	120,132	399,002
December 31, 2022	123,783	1,355,169	168,638	518,283
Proved undeveloped reserves, as of:				
December 31, 2020	125,402	1,040,297	110,776	409,561
December 31, 2021	116,425	1,071,025	120,257	415,186
December 31, 2022	146,237	1,537,089	179,065	581,483

	Developed	Undeveloped	Total
		(MBoe)	
Proved reserves, January 1, 2020	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
Revisions of previous estimates	75,005	70,370	145,375
Extensions, discoveries and other additions	960	—	960
Acquisition of reserves	519	7,594	8,113
Dispositions	—	—	—
Production	(71,333)	—	(71,333)
Undeveloped reserves converted to developed	72,339	(72,339)	—
Proved reserves, December 31, 2021	399,002	415,186	814,188

	Developed	Undeveloped	Total
		(MBoe)	
Revisions of previous estimates	14,223	160,071	174,294
Extensions, discoveries and other additions	—	—	—
Acquisition of reserves	95,227	101,160	196,387
Dispositions	(65)	—	(65)
Production	(85,038)	—	(85,038)
Undeveloped reserves converted to developed	94,934	(94,934)	—
Proved reserves, December 31, 2022	518,283	581,483	1,099,766

2022 Activity. During 2022, we increased proved reserves by 285.6 MMBoe, or 35 percent, relative to December 31, 2021. The increase in proved reserves was primarily due to (i) the reserves acquired in the Great Western Acquisition, (ii) positive revisions resulting from our development activities and (iii) upward revisions as a result of significant improvements in commodity prices during 2022, resulting in better economics. In 2022, we produced 85.0 MMBoe.

Revisions of Previous Estimates - Proved Developed Reserves. Proved developed reserves experienced a net positive revision of 14.2 MMBoe primarily due to an increase of 25.4 MMBoe as a result of extended well lives directly correlated with the improved average prices for crude oil, natural gas and NGLs in 2022 and a 15.0 MMBoe increase related to our operated and non-operated current year drilling activities not included within our five year development plan in the prior year. The positive revisions were partially offset by a 14.7 MMBoe decrease associated with higher operating costs and a decrease of 11.5 MMBoe related to performance revisions and other factors.

Revisions of Previous Estimates - PUDs. Net upward revisions to our previous PUD reserves estimates of 160.1 MMBoe were due to a 360.9 MMBoe increase related to changes to our drilling schedule, additional locations from denser spacing units and additional locations on proved acreage resulting from our 2022 development activities and a 4.3 MMBoe increase related to extended well lives directly correlated with the improved average prices for crude oil, natural gas and NGLs in 2022. The positive revisions were partially offset by decreases of (i) a 157.8 MMBoe related to PUD locations that were reclassified to unproven reserves due to changes in our drilling schedule, (ii) 38.7 MMBoe related to performance revisions, degradation for denser spacing units and other items and (iii) 8.6 MMBoe relating to locations no longer expected to be developed within five years of their initial recording in accordance with SEC rules. Drilling schedule changes mainly resulted from PUD downgrades associated with revised drilling plans following the completion of the Great Western Acquisition.

Acquisitions of Reserves - Proved Developed Reserves and PUDs. Proved developed and PUD reserves acquired primarily pertain to the Great Western Acquisition completed in May 2022.

During 2022, our conversion rate was 18 percent and we converted 94.9 MMBoe of PUD reserves at December 31, 2021 to proved developed reserves as of December 31, 2022.

Based on economic conditions on December 31, 2022, our approved development plan provides for the development of our remaining PUD locations within five years of the date such reserves were initially recorded. The level of capital spending, including any capital needed for any settlement of our asset retirement obligations, necessary to execute our development plan is consistent with our recent performance and updated drilling program.

2021 Activity. During 2021, we increased proved reserves by 83.1 MMBoe, or 11 percent, relative to December 31, 2020. The increase in proved reserves was primarily due to positive revisions resulting from our development activities and significant improvements in commodity prices during 2021, resulting in better economics. In 2021, we produced 71.3 MMBoe.

Revisions of Previous Estimates - Proved Developed Reserves. Proved developed reserves experienced a net positive revision of 75.0 MMBoe primarily due to (i) an increase of 44.3 MMBoe as a result of extended well lives directly correlated with the higher average prices for crude oil, natural gas and NGLs in 2021, (ii) a 24.9 MMBoe increase related to our operated and non-operated current year drilling activities not included within our five year development plan in the prior year, and (iii) an increase of 8.9 MMBoe related to performance revisions and other factors. The positive revisions were partially offset by a 3.1 MMBoe decrease associated with higher operating costs.

Revisions of Previous Estimates - PUDs. Net upward revisions to our previous PUD reserves estimates of 70.4 MMBoe were due to (i) a 166.5 MMBoe increase related to additional locations on proved acreage resulting from our 2021 development activities and changes to our drilling schedule resulting from state regulatory permitting process changes passed in 2021, (ii) a 8.6 MMBoe increase related to extended well lives directly correlated with the upward pricing adjustments due to improved average prices for crude oil, natural gas and NGLs in 2021, and (iii) 3.5 MMBoe related to performance revisions and other items. The positive revisions were partially offset by a 96.4 MMBoe downward revision primarily related to PUD locations that were reclassified to unproven reserves in our Wattenberg Field due to changes to our drilling schedule mainly resulting from state regulatory permitting process changes passed in 2021. Finally, a reduction of 11.8 MMBoe was recognized for locations no longer expected to be developed within five years of their initial recording in accordance with SEC rules.

Extensions, Discoveries and Other Additions - Proved Developed Reserves. Developed activity for 2021 included the addition of 1.0 MMBoe of developed reserves related to two gross newly turned-in-line wells in the Delaware Basin.

Acquisitions of Reserves - Proved Developed Reserves and PUDs. Proved developed and PUD reserves acquired primarily pertains to certain nonmonetary exchanges during 2021.

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 a 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 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 was recognized for locations no longer expected to be developed 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.

Results of Operations for Crude Oil and Natural Gas Producing Activities

The results of operations for crude oil and natural gas producing activities for the periods presented below:

	Year Ended December 31,		
	2022	2021	2020
		(in thousands)	
Revenues:			
Crude oil, natural gas and NGLs sales	$ 4,296,681	$ 2,552,558	$ 1,152,555
Commodity price risk management gain (loss), net	(463,611)	(701,456)	180,270
	3,833,070	1,851,102	1,332,825
Expenses:			
Lease operating expenses	262,986	180,659	161,346
Production taxes	311,778	165,209	59,368
Transportation, gathering and processing expenses	124,577	100,403	77,835
Exploration expense	13,079	1,064	1,376
Depreciation, depletion and amortization	741,906	627,466	611,003
Accretion of asset retirement obligations	13,408	12,086	10,072
Impairment of properties and equipment	6,762	402	882,393
(Gain) loss on sale of properties and equipment	212	(912)	(724)
	1,474,708	1,086,377	1,802,669
Results of operations for crude oil and natural gas producing activities before provision for income taxes	2,358,362	764,725	(469,844)
Income tax (expense) benefit	(499,973)	(37,013)	5,168
Results of operations for crude oil and natural gas producing activities, excluding corporate overhead and interest costs	$ 1,858,389	$ 727,712	$ (464,676)

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 for the periods presented:

	Year Ended December 31,		
	2022	2021	2020
		(in thousands)	
Acquisition of properties: (1)			
Proved properties	$ 2,093,993	$ 1	$ 1,618,000
Unproved properties	9,547	3,151	114,202
Development costs (2)	1,092,985	583,488	528,686
Exploration costs: (3)			
Exploratory drilling	24,861	6,902	12,892
Geological and geophysical	17	64	253
Total costs incurred	$ 3,221,403	$ 593,606	$ 2,274,033

(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, 2022, 2021 and 2020, $356.0 million, $227.8 million and $270.7 million, respectively, were incurred to convert proved undeveloped reserves to proved developed reserves from the prior year end.

(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,	
	2022	2021
	(in thousands)	
Proved crude oil and natural gas properties	$ 11,324,756	$ 8,310,018
Unproved crude oil and natural gas properties	156,418	306,181
Uncompleted wells, equipment and facilities	686,779	371,360
Capitalized costs	12,167,953	8,987,559
Accumulated DD&A	(4,957,848)	(4,218,330)
Capitalized costs, net	$ 7,210,105	$ 4,769,229

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 as of the dates indicated. 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,		
	2022	2021	2020
		(in thousands)	
Future estimated cash flows	$ 50,387,091	$ 26,143,031	$ 12,481,830
Future estimated production costs [1]	(11,124,864)	(6,325,129)	(4,209,459)
Future estimated development costs	(5,275,657)	(2,857,951)	(2,337,806)
Future estimated income tax expense	(7,070,756)	(3,088,187)	(301,507)
Future net cash flows	26,915,814	13,871,764	5,633,058
10% annual discount for estimated timing of cash flows	(11,928,425)	(5,963,592)	(2,350,879)
Standardized measure of discounted future estimated net cash flows	$ 14,987,389	$ 7,908,172	$ 3,282,179

(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 for the periods presented:

	Year Ended December 31,		
	2022	2021	2020
		(in thousands)	
Beginning of period	$ 7,908,172	$ 3,282,179	$ 3,310,334
Sales of crude oil, natural gas and NGLs production, net of production costs	(3,596,783)	(2,106,287)	(854,006)
Net changes in prices and production costs [1]	6,057,774	5,312,870	(1,771,019)
Extensions, discoveries and improved recovery, less related costs	—	20,201	14,110
Sales of reserves	(302)	—	(26,771)
Purchases of reserves	2,896,083	76,440	1,969,846
Development costs incurred during the period	558,477	338,098	329,495
Revisions of previous quantity estimates	2,794,615	2,645,379	(775,009)
Changes in estimated income taxes	(2,265,261)	(1,628,304)	354,369
Net changes in future development costs	(451,433)	(168,332)	367,630
Accretion of discount	1,163,956	345,454	572,483
Timing and other	(77,909)	(209,526)	(209,283)
End of period	$ 14,987,389	$ 7,908,172	$ 3,282,179

(1) Our weighted average price, net of production costs per Boe, in our 2022 reserve report increased to $35.70 as compared to $24.34 for 2021 and $11.32 for 2020.

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.

PDC ENERGY, INC.
SUPPLEMENTAL INFORMATION
(Unaudited)

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)		
2022:				
Allowance for doubtful accounts	$ 6,055	$ (446)	$ (164)	$ 5,445
Allowance for expirations of unproved crude oil and natural gas properties	206,328	864	(127,185)	80,007
2021:				
Allowance for doubtful accounts	$ 6,763	$ (359)	$ (349)	$ 6,055
Allowance for expirations of unproved crude oil and natural gas properties	224,019	—	(17,691)	206,328
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

(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, 2022, 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, 2022.

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, 2022, 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, 2022.

The effectiveness of our internal control over financial reporting as of December 31, 2022 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, 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

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 2023 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 2023 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 2023 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 2023 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 2023 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	Membership Interest Purchase Agreement, dated as of February 26, 2022, by and among PDC Energy, Inc., Great Western Petroleum, LLC, and the members of Great Western Petroleum, LLC.	8-K	001-37419	2.1	2/28/2022	
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				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
4.3	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	
4.4	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	
10.1	Form of Indemnification Agreement.	8-K	000-07246	10.1	6/8/2015	
10.2	Amended and Restated 2010 Long-Term Equity Compensation Plan, as amended.	10-K	001-37419	10.5	2/22/2016	
10.3	Executive Severance Compensation Plan, as amended and restated.	10-Q	001-37419	10.1	8/6/2020	
10.4	Form of 2013 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.10	2/27/2013	
10.5	Form of 2014 Restricted Stock/Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.5	2/19/2015	
10.6	Form of 2015 Stock Appreciation Rights Agreement.	10-K	000-07246	10.5.8	2/19/2015	
10.7	Form of 2020 Performance Share Agreement.	10-Q	001-37419	99.1	5/7/2020	
10.8	Form of 2020 Restricted Stock Unit Agreement (Executives).	10-Q	001-37419	99.3	5/7/2020	
10.9	Form of 2021 Performance Share Agreement.	10-Q	001-37419	99.1	5/6/2021	
10.10	Form of 2021 Restricted Stock Unit Agreement (Directors).	10-Q	001-37419	99.2	5/6/2021	
10.11	Form of 2021 Restricted Stock Unit Agreement (Executives).	10-Q	001-37419	99.3	5/6/2021	
10.12	Form of 2022 Performance Share Agreement.	10-Q	001-37419	99.1	5/4/2022	
10.13	Form of 2022 Restricted Stock Unit Agreement (Directors).	10-Q	001-37419	99.2	5/4/2022	
10.14	Form of 2022 Restricted Stock Unit Agreement (Executives).	10-Q	001-37419	99.3	5/4/2022	
10.15	Employment Agreement with Lance A. Lauck, as amended.	10-Q	001-37419	10.2	8/6/2020	
10.16	2018 Equity Incentive Plan.	8-K	001-37419	10.1	5/31/2018	
10.17	Amendment No. 1 to PDC Energy, Inc. 2018 Equity Incentive Plan.	8-K	001-37419	10.1	5/27/2020	
10.18	SRC Energy Inc. 2015 Equity Incentive Plan.	8-K	001-37419	10.1	1/14/2020	
10.19	Fifth Amended and Restated Credit Agreement, dated as of November 2, 2021 among PDC Energy, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent and The Lenders Party Hereto	10-Q	001-37419	10.1	11/3/2021	
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

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith
		Form	SEC File Number	Exhibit	Filing Date	
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
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 22, 2023

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 22, 2023
/s/ R. Scott Meyers R. Scott Meyers	Senior Vice President and Chief Financial Officer (principal financial officer)	February 22, 2023
/s/ Troy M. Welling Troy Welling	Chief Accounting Officer (principal accounting officer)	February 22, 2023
/s/ Mark E. Ellis Mark E. Ellis	Non-Executive Chairman of the Board of Directors	February 22, 2023
/s/ Pamela R. Butcher Pamela R. Butcher	Director	February 22, 2023
/s/ Paul J. Korus Paul J. Korus	Director	February 22, 2023
/s/ Lynn A. Peterson Lynn A. Peterson	Director	February 22, 2023
/s/ Carlos A. Sabater Carlos A. Sabater	Director	February 22, 2023
/s/ Diana L. Sands Diana L. Sands	Director	February 22, 2023

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.

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.

Intensity - Greenhouse gas and methane intensity is reported as total metric tons of methane emissions divided by gross annual production in MBOE.

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.