Matador
RESOURCES COMPANY

NYSE: MTDR

STRIDING FORWARD
MEETING CHALLENGES
CAPITALIZING ON EXPERIENCE

2019 ANNUAL REPORT

MATADOR RESOURCES COMPANY

Matador is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Its current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. Matador also operates in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana. Additionally, Matador conducts midstream operations, primarily through its midstream joint venture, San Mateo, in support of its exploration, development and production operations and provides natural gas processing, oil transportation services, natural gas, oil and salt water gathering services and salt water disposal services to third parties.

FINANCIAL AND OPERATING HIGHLIGHTS

($ in millions, unless otherwise noted)	2017	2018	2019
Operating Data			
Oil and Natural Gas Revenues	$ 528.7	$ 800.7	$ 892.3
% Oil in Revenues	73%	79%	85%
Net Income[1]	$ 125.9	$ 274.2	$ 87.8
Earnings per Diluted Common Share[1]	$ 1.23	$ 2.41	$ 0.75
Adjusted EBITDA[2]	$ 336.1	$ 553.2	$ 610.8
Balance Sheet Data			
Cash	$ 96.5	$ 64.5	$ 40.0
Net Property and Equipment	$ 1,881.5	$ 3,122.9	$ 3,699.6
Total Assets	$ 2,145.7	$ 3,455.5	$ 4,069.7
Current Liabilities	$ 282.6	$ 330.0	$ 399.8
Long-Term Liabilities	$ 605.5	$ 1,345.8	$ 1,700.5
Total Shareholders' Equity	$ 1,257.5	$ 1,779.7	$ 1,969.5
Net Production Volumes			
Oil (MBbl)	7,851	11,141	13,984
Natural Gas (Bcf)	38.2	47.3	61.1
Total Oil Equivalent (MBOE)[3],[4]	14,212	19,026	24,164
% Oil in Production Volumes[4]	55%	59%	58%
Average Daily Production (BOE/d)[4]	38,936	52,128	66,203
Reserves Information			
Total Proved Reserves (MMBOE)[4],[5]	152.8	215.3	252.5
% Oil in Proved Reserves[4]	57%	57%	59%
Standardized Measure	$ 1,258.6	$ 2,250.6	$ 2,034.0
PV-10[6]	$ 1,333.4	$ 2,579.3	$ 2,248.2
Realized Pricing			
Oil, with Realized Derivatives (per Bbl)	$ 48.81	$ 57.38	$ 54.98
Natural Gas, with Realized Derivatives (per Mcf)	$ 3.70	$ 3.46	$ 2.18

(1) Attributable to Matador Resources Company shareholders after giving effect to amounts attributable to third-party non-controlling interests.

(2) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "Adjusted EBITDA Reconciliation" at the end of this annual report.

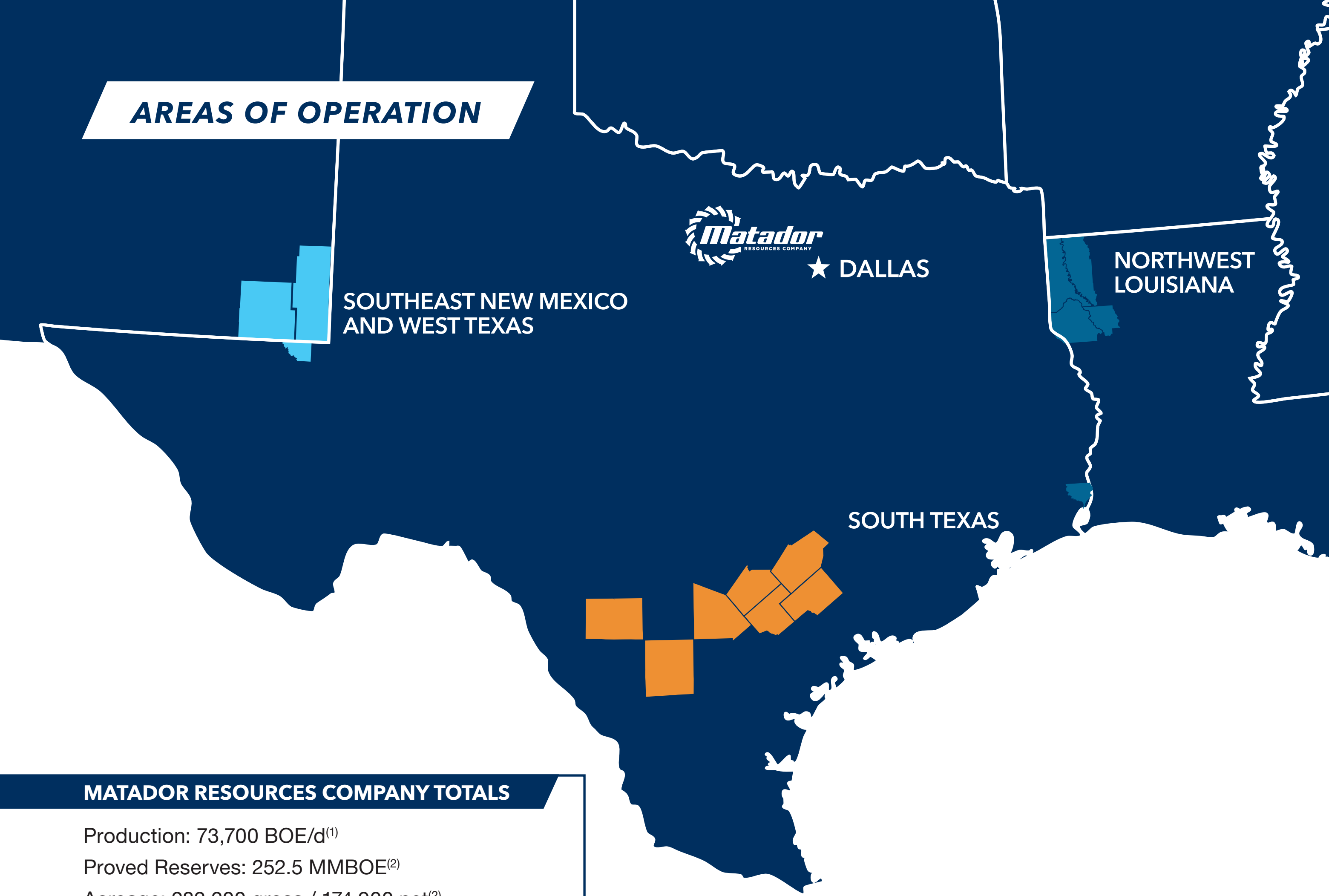
(3) Thousands of barrels of oil equivalent.

(4) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) Millions of barrels of oil equivalent.

(6) PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "Business — Estimated Proved Reserves" in the Annual Report on Form 10-K enclosed herein.

AREAS OF OPERATION



MATADOR RESOURCES COMPANY TOTALS

Production: 73,700 BOE/d(1)
Proved Reserves: 252.5 MMBOE(2)
Acreage: 282,200 gross / 174,900 net(2)
Locations: 5,932 gross / 2,658 net(2)

SOUTHEAST NEW MEXICO AND WEST TEXAS

Production: 61,500 BOE/d(1)
Proved Reserves: 232.8 MMBOE(2)
Acreage: 231,300 gross / 128,200 net(2)
Locations: 5,287 gross / 2,333 net(2)

SOUTH TEXAS

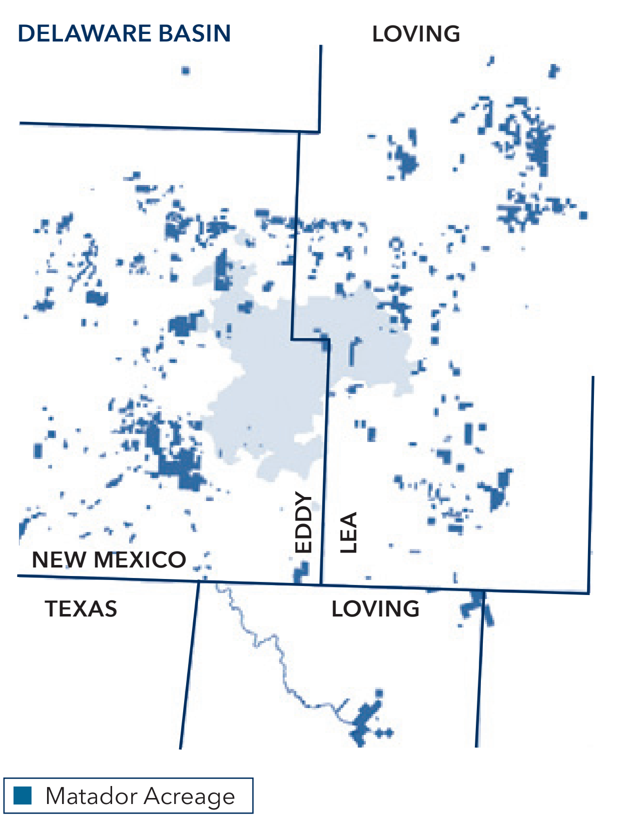
Production: 3,600 BOE/d(1)
Proved Reserves: 11.2 MMBOE(2)
Acreage: 31,200 gross / 28,400 net(2)
Locations: 234 gross / 196 net(2)

NORTHWEST LOUISIANA

Production: 8,600 BOE/d(1)
Proved Reserves: 8.5 MMBOE(2)
Acreage: 19,700 gross / 18,300 net(2)
Locations: 411 gross / 129 net(2)

(1) For the three months ended December 31, 2019.
(2) At December 31, 2019.

SOUTHEAST NEW MEXICO AND WEST TEXAS



Note: All acreage as of December 31, 2019. Some tracts not shown on map.

DEAR SHAREHOLDERS AND FRIENDS

Much in our lives has changed since late February. As I write this letter in April 2020, we find our nation and our industry in the midst of the global Coronavirus pandemic and an oil "price war" between Russia and Saudi Arabia. With this in mind, all of us at Matador would like first to extend our prayers and best wishes to you and your families during this tumultuous time. We hope this annual report will find you working, in good health and coping well with these days of confusion and chaos. Our plan to address and overcome these issues and challenges is set out below. The plan is off to a good start, and we believe we will emerge from these crises a better, stronger company.

MATADOR'S OUTLOOK AND PLANS GOING FORWARD

The fallout from this oil crisis and the Coronavirus pandemic happened very quickly, and we, like many of you, are working day-by-day to determine the best course of action moving forward. That said, Matador (ironically) began 2020 on a very strong note, and in late February, we were proud to announce that the fourth quarter of 2019 and full year 2019 were the best quarter and the best year, respectively, in the Company's history.

During the fourth quarter of 2019, Matador reported record quarterly production of 73,700 barrels of oil equivalent ("BOE") per day, an increase of 33% year-over-year, comprised of 42,100 barrels of oil per day and 190.0 million cubic feet of natural gas per day, both also quarterly records, and Matador's proved oil and natural gas reserves increased 17% year-over-year to approximately 253 million BOE (an all-time high). San Mateo, our midstream joint venture, also delivered a record quarter in the fourth quarter of 2019, both operationally and financially, including an all-time high for third-party midstream services revenues of $17.7 million, a two-fold year-over-year increase.

Thus, as we began 2020, the fundamentals in our businesses were hitting their marks. Oil was selling at $62 per barrel, and the outlook was very positive. Free cash flow was in sight for 2021. Matador had enjoyed 22 straight quarters — 5½ years — where Matador had met or exceeded the consensus projections of industry analysts for quarterly performance.

Then, in early February, the global effects of the Coronavirus pandemic began to manifest themselves. By early March, following the OPEC+ meeting in Vienna, the oil price war between Russia and Saudi Arabia erupted. As a result of these two cataclysmic events, the U.S. oil business has suffered a devastating blow, and stock prices for much of our industry plummeted by 80 to 90%. In response, the Matador team has taken swift and decisive actions to modify our plans for 2020 to meet the challenges of the demand destruction and the supply disruption caused by these two "black swan" events.

As always, but particularly in times like these, Matador's first priority is to protect the balance sheet and position ourselves for the long run. To that end, on March 11, 2020, Matador was one of the first companies in the industry to announce changes to its 2020 operating plan and was the very first to affirm its alignment with shareholders and bondholders by voluntarily reducing compensation throughout the entire organization for 2020. I voluntarily agreed to reduce my base salary by 25%, the Board members have agreed to reduce their compensation by 25% and the executive officers and vice presidents have agreed to reduce their base salaries by 20% and 10%, respectively. The rest of the staff pitched in, too, by taking a 5% cut in pay. I am also pleased to report that almost two-thirds of the Matador staff, including Board members, executive and senior officers, special advisors, employees and myself — approximately 200 individuals — purchased stock and/or bonds in the most recent trading period open to us in early March.

Matador has taken further actions to protect its balance sheet by reducing its expected capital spending significantly and by selling, leasing or trading non-core assets. Other actions include reducing our operated drilling program from six to three rigs, lowering certain operating costs (in particular, LOE and G&A) and continuing to pursue divestitures of non-core assets. Matador believes these actions, among other items, could save $325 million or more in 2020. The Company is currently evaluating multiple options to optimize its drilling and completions activities and plans to keep two of its three drilling rigs operating in the Stateline asset area in Eddy County, New Mexico, where we are expecting to drill a number of our high potential wells — with estimated ultimate recoveries of 1.5 to 2.0 million BOE apiece. In addition, Matador has the ability to earn up to $150 million in performance incentives from Five Point Energy LLC over the next several years related to the formation of San Mateo II in February 2019, and these performance incentives would be in addition to the remaining $29.4 million in performance incentives that may be earned over the next two years related to the formation of San Mateo I.

Matador is also evaluating other options for increasing our cash flow and for further reducing operating and capital expenses, if necessary, in the second half of 2020. In fact, we are prepared to take whatever additional steps are necessary to protect the balance sheet and our businesses until oil and natural gas prices improve. Your Board, your staff and I all have the confidence that we have the great rock, the great people and the financial strength and flexibility necessary to accomplish these tasks and get to the other side.

UPCOMING MILESTONES

Although we are scaling back our operations in 2020, Matador remains very excited about the prospects for our exploration and production business and for our midstream business. We started the year strong operationally, and there are certain key events that should serve as important milestones and catalysts to mark our progress as we continue in 2020, as follows:

- The first six Rodney Robinson wells have been recently completed and turned to sales and have performed "better than expected." Four other wells were turned to sales this month, too. By mid-summer 2020, Matador expects to complete and turn to sales five Leatherneck wells in our Greater Stebbins area, and five Ray wells in the Rustler Breaks asset area. These ten Ray and Leatherneck wells are two-mile laterals and are expected to be strong producers that will help to increase cash flow and to feed San Mateo's system.
- In September 2020, we anticipate beginning production from our first 13 wells to be drilled and completed in the Stateline asset area (the "Boros" wells). We are very excited to get these wells completed and turned to sales, as we anticipate they should be among the best wells we have drilled in the Delaware Basin. These wells should result in a significant increase in our production in the fourth quarter of 2020 and should also result in a significant increase in San Mateo's throughput volumes in the fourth quarter. Over time, most of these wells are expected to recover 1.5 to 2.0 million BOE each as noted above. In addition, Matador has a 100% working interest and a higher than normal 87.5% net revenue interest in each of these 13 wells to boost the economic returns.

MIDSTREAM

In late summer 2020, San Mateo plans to complete its 200 million cubic feet per day expansion of the Black River Processing Plant in Eddy County, New Mexico, which will almost double San Mateo's processing capability to 460 million cubic feet of gas per day. In addition, San Mateo expects to construct two natural gas trunk lines connecting the natural gas processing facilities with the Stateline asset area and the Greater Stebbins area, and provide local oil, natural gas and water gathering and water disposal infrastructure in the Stateline asset area and the Greater Stebbins area. In this joint venture, Five Point has been an active partner helping with strategy and contributing both financial and operational acumen and providing significant drilling incentives to Matador. San Mateo is one of the few companies in Southeast New Mexico to offer a "three pipe system" for oil, natural gas and water, which further enhances the "billion dollar plus" value of San Mateo.

MATADOR'S FINANCIAL POSITION REMAINS STRONG

Matador is confident that it has the liquidity to work its way through the current difficulties. Matador can draw upon the cash flow from its production, its savings from extensive budget cuts and its access to borrowing availability under its revolving credit facility. In this regard, Matador and its lenders completed and closed the Spring 2020 borrowing base redetermination in late February 2020, certainly among the very first oil and natural gas companies to do so. As a result of this process,

- Matador's borrowing base was affirmed as a conforming loan at $900 million unanimously — even at an oil price of approximately $37 per barrel by our lead bank. In total, all 11 lenders in the Company's commercial banking group and all 11 of their reservoir engineering groups reviewed our oil and natural gas assets and approved this borrowing availability based on our financial metrics, the asset quality and our lending history.
- Most banks increased their loan commitments to the Company's reserves-based credit facility so that Matador's facility was oversubscribed. Matador elected to increase the borrowing commitment to only $700 million, leaving an additional $200 million in availability from the banks for future consideration.

We were very pleased with and appreciative of this strong show of support from our commercial bank group and believe their actions reflect the strength of our relationship with the banks and the quality of Matador's performance and assets, management and technical teams. Furthermore, unlike many others in our industry, Matador faces no near-term debt maturities, as our reserves-based credit facility matures in October 2023, and our senior unsecured notes mature in September 2026. Matador also has various hedges in place to protect its balance sheet and cash flow.

CLOSING REMARKS AND ANNUAL MEETING INVITATION

These are difficult, challenging and unprecedented times for all of us in the oil and natural gas industry and for our nation. I have learned over the years, however, that such times can often bring unexpected opportunities to improve the Company's assets, processes and staff, and we will remain open to all such possibilities as we navigate the days ahead. We are grateful to have you as shareholders and we appreciate all your trust, support and patience. We have weathered previous challenges together and emerged better for it. I remain confident we can successfully meet today's challenges as well.

We hope that the current Coronavirus pandemic is over and your life is getting back to normal by the time of our annual shareholders' meeting scheduled for June 5. If so, we hope you will be able to join us for the meeting in Dallas at The Westin Galleria Dallas Hotel to meet and visit with our directors and key staff members in person. We hope to see all of you there, but, if we are unable to meet in person, we will host the meeting virtually and will provide additional details separately. It should be one of our more interesting meetings. Please feel free to follow up with David Lancaster or me with any questions or concerns that you may have.

Sincerely,

Joseph Wm. Foran

Founder, Chairman and Chief Executive Officer

BOARD OF DIRECTORS

Joseph Wm. Foran

Founder, Chairman and Chief Executive Officer of Matador Resources Company (Matador II); Founder, Chairman and Chief Executive Officer of Matador Petroleum Corporation (Matador I)

Timothy E. Parker

Lead Independent Director; Former Portfolio Manager and Analyst – Natural Resources, T. Rowe Price & Associates

R. Gaines Baty

Deputy Lead Independent Director; Chief Executive Officer, R. Gaines Baty Associates, Inc.; Published Author

Reynald A. Baribault

Director; Vice President/Engineering and Co-Founder, NP Resources, LLC; President and CEO, IPR Energy Partners, LLC; Former Vice President, Netherland, Sewell & Associates, Inc.

Craig T. Burkert

Director; Chief Financial Officer, ROMCO Equipment Co.

William M. Byerley

Director; Retired Partner (energy focus), PricewaterhouseCoopers (PwC)

Matthew P. Clifton

Director; Former Chairman and Chief Executive Officer, Holly Logistics Services, L.L.C.

Monika U. Ehrman

Director; Professor of Law, University of Oklahoma College of Law; Petroleum Engineer; Former Oil and Gas Company In-House Legal Counsel

Julia P. Forrester Rogers

Director; Professor of Law, Southern Methodist University Dedman School of Law; Former Associate Provost, SMU; Former Real Estate Attorney, Thompson & Knight LLP

David M. Posner

Director; President, EnVent Energy LLC; Former Vice President, Marketing, Snyder Oil Corporation

Kenneth L. Stewart

Director; Executive Vice President, Compliance and Legal Affairs, Children's Health System of Texas; Retired Partner, Chair – United States, Norton Rose Fulbright US LLP

SPECIAL BOARD ADVISOR

James A. Rolfe

Of Counsel, Elliott Sauter, PLLC; Retired United States Attorney, Northern District of Texas

BOARD ADVISORS

Rick H. Fenlaw

Owner, Fenlaw Land Services

Wade I. Massad

Managing Member, Cleveland Capital Management, LLC; Formerly with KeyBanc Capital Markets and RBC Capital Markets

Back row (left to right): Kenneth L. Stewart, Reynald A. Baribault, Timothy E. Parker, R. Gaines Baty, Matthew P. Clifton
Front row (left to right): Craig T. Burkert, Julia P. Forrester Rogers, Joseph Wm. Foran, Monika U. Ehrman, William M. Byerley

EXECUTIVE OFFICERS AND SENIOR MANAGEMENT

Joseph Wm. Foran
Founder, Chairman and Chief Executive Officer

Matthew V. Hairford
President and Chair of Operating Committee

David E. Lancaster
Executive Vice President and Chief Financial Officer

Craig N. Adams
Executive Vice President and Chief Operating Officer – Land, Legal and Administration

Billy E. Goodwin
Executive Vice President and Chief Operating Officer – Drilling, Completions and Production

Van H. Singleton, II
Executive Vice President – Land

Bradley M. Robinson
Executive Vice President of Reservoir Engineering and Chief Technology Officer

G. Gregg Krug
Executive Vice President – Marketing and Midstream Strategy

Christopher P. Calvert
Senior Vice President of Operations

W. Thomas Elsener
Senior Vice President of Reservoir Engineering and Senior Asset Manager

Bryan A. Erman
Senior Vice President and Co-General Counsel

Dr. Edmund L. Frost III
Senior Vice President of Geoscience

Robert T. Macalik
Senior Vice President and Chief Accounting Officer

Matthew D. Spicer
Senior Vice President and General Manager of Midstream

Glenn W. Stetson
Senior Vice President of Production and Asset Manager

Brian J. Willey
Senior Vice President and Co-General Counsel

Surrounding Joe Foran, Matador's Chairman and CEO (front, middle), are members of Matador's staff. Matador had a total of 304 full-time employees at December 31, 2019. (Approximately 2/3 purchased MTDR stock in Q1 2020.)

ENVIRONMENTAL, SOCIAL AND GOVERNANCE (ESG)

Matador has always maintained an active program since inception.

ENVIRONMENTAL

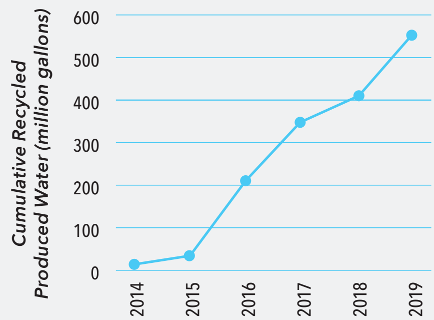
EMISSIONS

REDUCING EMISSIONS SINCE 2017

Greenhouse Gas	↓ 6%
Emissions Intensity Rate	↓ 33%
Methane Intensity Rate	↓ 33%
Natural Gas Average Days Turned to Sales	↓ 38%

RECYCLED WATER

OVER 550 MILLION GALLONS RECYCLED BY YE 2019



OPERATIONS AND LAND

>55% OF OIL AND >78% OF WATER PRODUCED FROM THE DELAWARE BASIN IS TRANSPORTED ON PIPE[(1)]

~460,000 truckloads off the road per year

~15 miles removed per roundtrip truckload

~7 million trucking miles per year eliminated

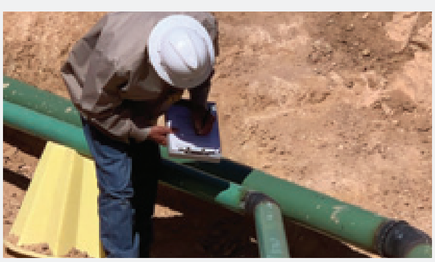
~1,000 metric tons of CO_2e per year avoided

(1) Represents Matador's average gross operated oil and water transported on pipes in the Delaware Basin in 2019 as of December 2019.

SOCIAL

PROACTIVE SAFETY CULTURE

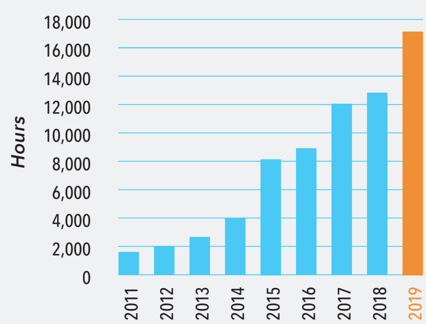
OVER 1.4 MILLION EMPLOYEE MAN-HOURS AND ZERO LOST TIME ACCIDENTS SINCE 2017



Pipeline inspection.

CONTINUING EDUCATION

OVER 17,000 HOURS OF EMPLOYEE CONTINUING EDUCATION IN 2019



GOVERNANCE

BOARD COMPOSITION

- Diverse and independent board
- Lead independent director
- 10 of 11 independent directors
- No "overboarding"
- Female membership since 1988[(2)]

ENGAGED BOARD OF DIRECTORS WITH MAJORITY VOTING STANDARD

ANNUAL "SAY ON PAY" VOTING

(2) Dating to inception of predecessor company, Matador Petroleum Corporation.

COMMUNITY AND CHARITY

SUPPORTING COMMUNITIES AND CHARITIES WHERE WE LIVE, WORK AND OPERATE

Hundreds of toys donated to the Eddy County, NM Sheriff's Office Christmas toy drive.

Matador employees and families participating in Giving Day at the North Texas Food Bank.

Team Matador at the 2019 Tough Mudder Obstacle Race.

For more information, visit our website at www.matadorresources.com under the heading "Investor Relations — ESG."

Matador
RESOURCES COMPANY

NYSE: MTDR

2019 FORM 10-K

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2019

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: 001-35410

MATADOR RESOURCES COMPANY

(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**27-4662601** (I.R.S. Employer Identification No.)
5400 LBJ Freeway, Suite 1500 **Dallas, Texas** (Address of principal executive offices)	**75240** (Zip Code)

Registrant's telephone number, including area code: (972) 371-5200

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

Title of each class	Trading symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.01 per share	**MTDR**	**New York Stock Exchange**

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

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

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

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

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

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

Large accelerated filer ☑	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant's most recently completed second fiscal quarter was $2,187,634,344.

As of February 28, 2020, there were 116,569,389 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Annual Report on Form 10-K, to the extent not set forth herein, is incorporated by reference to the registrant's definitive proxy statement relating to the 2020 Annual Meeting of Shareholders, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates.

Table of Contents

Cautionary Note Regarding Forward-Looking Statements

Certain statements in this Annual Report on Form 10-K (this "Annual Report") constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future by us or on our behalf. Such statements are generally identifiable by the terminology used such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecasted," "hypothetical," "intend," "may," "might," "plan," "potential," "predict," "project," "should," "would" or other similar words, although not all forward-looking statements contain such identifying words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: general economic conditions; our ability to execute our business plan, including whether our drilling program is successful; changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids; our ability to replace reserves and efficiently develop current reserves; costs of operations; delays and other difficulties related to producing oil, natural gas and natural gas liquids; delays and other difficulties related to regulatory and governmental approvals and restrictions; availability of sufficient capital to execute our business plan, including from future cash flows, increases in our borrowing base and otherwise; our ability to make acquisitions on economically acceptable terms; our ability to integrate acquisitions; weather and environmental conditions; the operating results of our midstream joint venture's expansion of the Black River cryogenic natural gas processing plant, including the timing of the further expansion of such plant; the timing and operating results of the buildout by our midstream joint venture of oil, natural gas and water gathering and transportation systems and the drilling of any additional salt water disposal wells, including in conjunction with the expansion of our midstream joint venture's services and assets into new areas in Eddy County, New Mexico; and the other factors discussed below and elsewhere in this Annual Report and in other documents that we file with or furnish to the United States Securities and Exchange Commission (the "SEC"), all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our estimated future reserves and the present value thereof;
- our cash flows and liquidity;
- our financial strategy, budget, projections and operating results;
- our oil and natural gas realized prices;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;
- our drilling of wells;
- our ability to negotiate and consummate acquisition and divestiture opportunities;
- government regulation and taxation of the oil and natural gas industry;

- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the integration of acquisitions with our business;
- our ability and the ability of our midstream joint venture to construct and operate midstream facilities, including the operation and expansion of our Black River cryogenic natural gas processing plant and the drilling of additional salt water disposal wells;
- the ability of our midstream joint venture to attract third-party volumes;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry, including in both the exploration and production and midstream segments;
- the effectiveness of our risk management and hedging activities;
- our technology;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results; and
- our plans, objectives, expectations and intentions contained in this Annual Report or in our other filings with the SEC that are not historical.

Although we believe that the expectations conveyed by the forward-looking statements in this Annual Report are reasonable based on information available to us on the date hereof, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We undertake no obligation to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

Part I

ITEM 1. BUSINESS.

In this Annual Report, (i) references to "we," "our" or the "Company" refer to Matador Resources Company and its subsidiaries as a whole (unless the context indicates otherwise), (ii) references to "Matador" refer solely to Matador Resources Company and (iii) references to "San Mateo" refer to San Mateo Midstream, LLC ("San Mateo I") together with San Mateo Midstream II, LLC ("San Mateo II"). For certain oil and natural gas terms used in this Annual Report, see the "Glossary of Oil and Natural Gas Terms" included in this Annual Report.

GENERAL

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana. Additionally, we conduct midstream operations, primarily through our midstream joint venture, San Mateo, in support of our exploration, development and production operations and provide natural gas processing, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties.

We are a Texas corporation founded in July 2003 by Joseph Wm. Foran, Chairman and CEO. Mr. Foran began his career as an oil and natural gas independent in 1983 when he founded Foran Oil Company with $270,000 in contributed capital from 17 friends and family members. Foran Oil Company was later contributed to Matador Petroleum Corporation upon its formation by Mr. Foran in 1988. Mr. Foran served as Chairman and Chief Executive Officer of that company from its inception until it was sold in June 2003 to Tom Brown, Inc., in an all cash transaction for an enterprise value of approximately $388.5 million.

On February 2, 2012, our common stock began trading on the New York Stock Exchange (the "NYSE") under the symbol "MTDR." Prior to trading on the NYSE, there was no established public trading market for our common stock.

Our goal is to increase shareholder value by building oil and natural gas reserves, production and cash flows and providing midstream services at an attractive rate of return on invested capital. We plan to achieve our goal by, among other items, executing the following business strategies:

- focus our exploration and development activities primarily on unconventional plays, including the Wolfcamp and Bone Spring plays in the Delaware Basin;
- identify, evaluate and develop additional oil and natural gas plays as necessary to maintain a balanced portfolio of oil and natural gas properties;
- continue to improve operational and cost efficiencies;
- identify and develop midstream opportunities that support and enhance our exploration and development activities and that generate value for San Mateo;
- maintain our financial discipline; and
- pursue opportunistic acquisitions, divestitures and joint ventures.

Despite a challenging commodity price environment since 2014, the successful execution of our business strategies in 2019 led to significant increases in our oil and natural gas production and proved oil and natural gas reserves. We also improved the capital efficiency of our drilling and completion operations and continued to improve our leasehold and minerals position in the Delaware Basin. In addition, we concluded several important financing transactions in 2019, including an increase in the borrowing base under our Credit Agreement (as defined below), two increases in the lender commitments under the San Mateo Credit Facility (as defined below) and the conversion of approximately $21.9 million of non-core assets to cash. San Mateo also achieved several important milestones in 2019, including the formation of San Mateo II, an increased natural gas gathering and processing commitment from an existing natural gas customer, significant additional acreage dedications from existing salt water disposal customers, an acreage dedication from a new oil customer and an increase in designed salt water disposal capacity. These achievements and transactions increased our operational flexibility and opportunities while preserving the strength of our balance sheet and our liquidity position.

2019 HIGHLIGHTS

Increased Oil, Natural Gas and Oil Equivalent Production

For the year ended December 31, 2019, we achieved record oil, natural gas and average daily oil equivalent production. In 2019, we produced 14.0 million Bbl of oil, an increase of 26%, as compared to 11.1 million Bbl of oil produced in 2018. We also produced 61.1 Bcf of natural gas, an increase of 29% from 47.3 Bcf of natural gas produced in 2018. Our average daily oil equivalent production for the year ended December 31, 2019 was 66,203 BOE per day, including 38,312 Bbl of oil per day and 167.4 MMcf of natural gas per day, an increase of 27%, as compared to 52,128 BOE per day, including 30,524 Bbl of oil per day and 129.6 MMcf of natural gas per day, for the year ended December 31, 2018. The increase in oil and natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin throughout 2019 as well as from our nine-well program in South Texas concluded in the first half of 2019 and non-operated Haynesville shale wells completed and placed on production during the third quarter of 2019. Oil production comprised 58% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the year ended December 31, 2019, as compared to 59% for the year ended December 31, 2018.

Increased Oil, Natural Gas and Oil Equivalent Reserves

At December 31, 2019, our estimated total proved oil and natural gas reserves were 252.5 million BOE, including 148.0 million Bbl of oil and 627.2 Bcf of natural gas, an increase of 17% from 215.3 million BOE, including 123.4 million Bbl of oil and 551.5 Bcf of natural gas, at December 31, 2018. The Standardized Measure of our total proved oil and natural gas reserves decreased 10% from $2.25 billion at December 31, 2018 to $2.03 billion at December 31, 2019. The PV-10 of our total proved oil and natural gas reserves decreased 13% from $2.58 billion at December 31, 2018 to $2.25 billion at December 31, 2019. The decreases in our Standardized Measure and PV-10 were primarily a result of lower weighted average oil and natural gas prices used to estimate proved reserves at December 31, 2019, as compared to December 31, 2018. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "—Estimated Proved Reserves."

Our proved oil reserves grew 20% to 148.0 million Bbl at December 31, 2019 from 123.4 million Bbl at December 31, 2018. Our proved natural gas reserves increased 14% to 627.2 Bcf at December 31, 2019 from 551.5 Bcf at December 31, 2018. This growth in oil and natural gas reserves was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin during 2019.

At December 31, 2019, proved developed reserves included 59.7 million Bbl of oil and 276.3 Bcf of natural gas, and proved undeveloped reserves included 88.3 million Bbl of oil and 351.0 Bcf of natural gas. Proved developed reserves and proved oil reserves comprised 42% and 59%, respectively, of our total proved oil and natural gas reserves at December 31, 2019. Proved developed reserves and proved oil reserves comprised 44% and 57%, respectively, of our total proved oil and natural gas reserves at December 31, 2018.

Operational Highlights

We focus on optimizing the development of our resource base by seeking ways to maximize our recovery per well relative to the cost incurred and to minimize our operating costs per BOE produced. We apply an analytical approach to track and monitor the effectiveness of our drilling and completion techniques and service providers. This allows us to better manage operating costs, the pace of development activities, technical applications, the gathering and marketing of our production and capital allocation. Additionally, we concentrate on our core areas, which allows us to achieve economies of scale and reduce operating costs. Largely as a result of these factors, we believe that we have increased our technical knowledge of drilling, completing and producing Delaware Basin wells, particularly over the past six years. We expect the Delaware Basin will continue to be our primary area of focus in 2020.

We completed and began producing oil and natural gas from 138 gross (65.7 net) wells in the Delaware Basin in 2019, including 76 gross (61.4 net) operated and 62 gross (4.3 net) non-operated wells. At December 31, 2019, our total acreage position in the Delaware Basin was approximately 231,300 gross (128,200 net) acres, primarily in Loving County, Texas and Lea and Eddy Counties, New Mexico. We have focused our Delaware Basin operations thus far on the following asset areas: the Wolf and Jackson Trust asset areas in Loving County, Texas, the Rustler Breaks and Arrowhead asset areas in Eddy County, New Mexico and the Antelope Ridge, Ranger and Twin Lakes asset areas in Lea County, New Mexico. Our Delaware Basin properties have become the most significant component of our asset portfolio. Our average daily oil equivalent production from the Delaware Basin increased approximately 23% to 55,599 BOE per day (84% of total oil equivalent production), including 35,184 Bbl of oil per day (92% of total oil production) and 122.5 MMcf of natural gas per day (73% of total natural gas production), in 2019, as compared to 45,237 BOE per day (87% of total oil equivalent production), including 28,026 Bbl of oil per day (92% of total oil production) and 103.3 MMcf of natural gas per day (80% of total natural gas production), in 2018. We expect our Delaware Basin production to increase in 2020 as we continue the delineation and development of these asset areas, as well as our new Stateline asset area in Eddy County, New Mexico, where we expect to begin production late in the third quarter of 2020.

Operational highlights in the Delaware Basin (as further described below in "—Exploration and Production Segment—Southeast New Mexico and West Texas—Delaware Basin" and "—Midstream Segment") in 2019 included:

- in our Rustler Breaks asset area, the results from our first two operated First Bone Spring tests, including the Garrett State Com 32-24S-29E RB #111H (Garrett #111H) well and the Paul 25-24S-28E RB #111H (Paul #111H) well, demonstrating the prospectivity of this formation and the continued delineation and development of previously tested horizons;
- in our Wolf asset area, the continuing success from several wells with longer laterals (greater than one mile) drilled and completed in the Wolfcamp A-XY interval;
- in our Jackson Trust asset area, the continued development of the Wolfcamp A-Lower interval;
- in our Arrowhead and Ranger asset areas, the results from our Wolfcamp A-XY completions, particularly in the Stebbins acreage block in the Arrowhead asset area, whose 24-hour initial potential ("IP") test results and subsequent well performance demonstrate the prospectivity of the Wolfcamp formation moving north in the Delaware Basin;

- in our Antelope Ridge asset area, the results from the Jeff Hart State Com #124H and #134H (Jeff Hart #124H and #134H) wells, our first two operated two-mile horizontal wells in the asset area, and the initiation of drilling operations on six wells in the western region of the asset area (the “Rodney Robinson” wells);
- in our Stateline asset area, the successful approval and receipt of 14 drilling permits from the Bureau of Land Management (“BLM”) and the initiation of drilling operations there in late December 2019;
- the transition to drilling longer laterals, whereby 29% of the operated horizontal wells we completed and turned to sales in 2019 had lateral lengths greater than one mile, as compared to 9% in 2018;
- the continuing improvement in capital efficiency as demonstrated by our average drilling and completion costs for all operated horizontal wells completed and turned to sales of approximately $1,165 per lateral foot in 2019, a decrease of 24% as compared to average drilling and completion costs of $1,528 per lateral foot in 2018;
- the initial transportation of much of our Delaware Basin residue natural gas production to the Texas Gulf Coast on the newly commissioned Gulf Coast Express Pipeline Project (the “GCX Pipeline”) beginning in late September 2019; and
- the significant progress made in our midstream operations, including (i) strong operating results in 2019, (ii) the initiation of an expansion of San Mateo’s cryogenic natural gas processing plant in Eddy County, New Mexico (the “Black River Processing Plant”) by an additional 200 MMcf per day of designed natural gas processing inlet capacity, which is anticipated to be placed in service during the summer of 2020, (iii) the initiation of San Mateo’s plans to construct large diameter natural gas gathering lines southward from the Stebbins area and surrounding leaseholds in the southern portion of the Arrowhead asset area (the “Greater Stebbins Area”) and northward from the Stateline asset area to connect these areas with the Black River Processing Plant, (iv) the addition of significant salt water disposal capacity in the Rustler Breaks asset area and the Greater Stebbins Area and (v) the progress made by San Mateo in increasing commitments, throughput volumes and acreage dedications from both new and existing customers.

We also concluded operations on our nine-well program in South Texas (initiated in late 2018) during the second quarter of 2019, which included turning to sales seven gross (6.9 net) wells in the Eagle Ford formation and one gross (1.0 net) well in the Austin Chalk formation in 2019. We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana during 2019, although we did participate in the drilling and completion of 26 gross (1.7 net) non-operated Haynesville shale wells that began producing in 2019, including two highly productive two-mile lateral wells completed and turned to sales by an affiliate of Chesapeake Energy Corporation (“Chesapeake”) during the third quarter of 2019.

Financing Transactions

We concluded several important financing transactions in 2019 that increased our operational flexibility and opportunities, while preserving the strength of our balance sheet and improving our liquidity position. These transactions included:

- the amendment of our third amended and restated credit agreement (the “Credit Agreement”) to increase the borrowing base to $900.0 million, which was further amended in February 2020 to increase our elected borrowing commitment from $500.0 million to $700.0 million;
- the increase of the lender commitments under San Mateo I’s credit facility (the “San Mateo Credit Facility”) to $375.0 million, using the accordion feature; and
- the conversion of approximately $21.9 million of non-core assets to cash during 2019. These properties were primarily located in South Texas and Northwest Louisiana and East Texas but included a small portion of our leasehold in a non-operated area of the Delaware Basin.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for additional information regarding these financing transactions.

Midstream Highlights

On February 25, 2019, we announced the formation of San Mateo II, a strategic joint venture with a subsidiary of Five Point Energy LLC ("Five Point") designed to expand our midstream operations in the Delaware Basin, specifically in Eddy County, New Mexico. San Mateo II is owned 51% by us and 49% by Five Point. As part of this transaction, we dedicated to San Mateo II acreage in the Greater Stebbins Area and the Stateline asset area pursuant to 15-year, fixed-fee agreements for oil, natural gas and salt water gathering, natural gas processing and salt water disposal. In addition, Five Point has committed to pay $125.0 million of the first $150.0 million of capital expenditures incurred by San Mateo II to develop facilities in the Greater Stebbins Area and the Stateline asset area. Five Point has also provided us the opportunity to earn deferred performance incentives of up to $150.0 million over the next several years as we execute our operational plans in and around the Greater Stebbins Area and the Stateline asset area, plus additional performance incentives for securing volumes from third-party customers.

San Mateo achieved strong operating results in 2019, highlighted by (i) increased third-party midstream services revenues, (ii) increased natural gas gathering and processing volumes, (iii) increased water gathering and water disposal volumes and (iv) increased oil gathering volumes, all as compared to 2018. San Mateo initiated construction on an additional 200 MMcf per day of designed natural gas processing inlet capacity as part of the expansion of the Black River Processing Plant, which is anticipated to be placed in service during the summer of 2020 and would bring the total designed inlet capacity of the Black River Processing Plant to 460 MMcf of natural gas per day. San Mateo also initiated plans to construct large diameter natural gas gathering lines southward from the Greater Stebbins Area and northward from the Stateline asset area to connect these areas with the Black River Processing Plant. During 2019, San Mateo added four commercial salt water disposal wells, two in the Rustler Breaks asset area and two in the Greater Stebbins Area, and expects to place into service one additional commercial salt water disposal well in the Rustler Breaks asset area in the first quarter of 2020, bringing San Mateo's designed salt water disposal capacity to approximately 335,000 Bbl per day.

During 2019, San Mateo received an increased natural gas gathering and processing commitment from an existing natural gas customer, plus other interruptible volumes, obtained significant additional acreage dedications from existing salt water customers and added an acreage dedication from a new oil customer. At certain times near the end of the third quarter and early in the fourth quarter of 2019, as a result of increased throughput from existing natural gas processing customers, San Mateo was operating the Black River Processing Plant at greater than 95% of the current designed inlet capacity of 260 MMcf per day.

Environmental, Social and Governance ("ESG") Initiatives

We maintain an active ESG program and continued working in 2019 to improve upon our various ESG efforts. For instance, we significantly increased the number of our production facilities operating on electrical grid power, lowering emissions by removing on-site generators. We increased the volumes of produced water we recycled in the Delaware Basin as well as the volumes of both produced water and oil transported via pipeline, taking trucks off the roads. We also reduced the number of well pads built in 2019 through our use of batch drilling and longer laterals, reducing our surface footprint. Finally, we continued our commitment to a proactive safety culture, with over 1.4 million employee man-hours and no lost time accidents since 2017.

EXPLORATION AND PRODUCTION SEGMENT

Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana. During 2019, we devoted most of our efforts and most of our capital expenditures to our drilling and completion operations in the Wolfcamp and Bone Spring plays in the Delaware Basin, as well as our midstream operations there. Since our inception, our exploration and development efforts have concentrated primarily on known hydrocarbon-producing basins with well-established production histories offering the potential for multiple-zone completions.

The following table presents certain summary data for each of our operating areas as of and for the year ended December 31, 2019.

			Producing Wells		Total Identified Drilling Locations (1)		Estimated Net Proved Reserves (2)		
	Gross Acreage	Net Acreage	Gross	Net	Gross	Net	MBOE(3)	% Developed	Avg. Daily Production (BOE/d)(3)
Southeast New Mexico/ West Texas:									
Delaware Basin (4)	231,300	128,200	757	354.0	5,287	2,332.4	232,793	39.0	55,599
South Texas:									
Eagle Ford (5)	31,200	28,400	143	121.4	234	196.3	11,219	65.5	4,009
Northwest Louisiana									
Haynesville	17,500	10,000	246	20.5	341	80.8	7,652	86.3	6,345
Cotton Valley (6)	16,100	14,900	66	40.7	70	48.3	866	100.0	250
Area Total (7)	19,700	18,300	312	61.2	411	129.1	8,518	87.7	6,595
Total	282,200	174,900	1,212	536.6	5,932	2,657.8	252,530	41.9	66,203

(1) Identified and engineered drilling locations. These locations have been identified for potential future drilling and were not producing at December 31, 2019. The total net engineered drilling locations are calculated by multiplying the gross engineered drilling locations in an operating area by our working interest participation in such locations. Each horizontal drilling location generally represents a one-mile lateral, although we anticipate that many of our future wells will have lateral lengths longer than one mile. At December 31, 2019, these engineered drilling locations included only 372 gross (168.5 net) locations to which we have assigned proved undeveloped reserves, primarily in the Wolfcamp or Bone Spring plays, but also in the Brushy Canyon, Avalon, Delaware and Strawn formations, in the Delaware Basin, 14 gross (13.7 net) locations to which we have assigned proved undeveloped reserves in the Eagle Ford and five gross (0.5 net) locations to which we have assigned proved undeveloped reserves in the Haynesville shale. Certain of these locations to which we have assigned proved undeveloped reserves may contemplate lateral lengths longer than one mile.

(2) These estimates were prepared by our engineering staff and audited by Netherland, Sewell & Associates, Inc., independent reservoir engineers. For additional information regarding our oil and natural gas reserves, see "—Estimated Proved Reserves" and Supplemental Oil and Natural Gas Disclosures included in the unaudited supplementary information in this Annual Report, which is incorporated herein by reference.

(3) Production volumes and proved reserves reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Includes potential future engineered drilling locations in the Wolfcamp, Bone Spring, Brushy Canyon, Strawn and Avalon plays on our acreage in the Delaware Basin at December 31, 2019.

(5) Includes one well producing oil from the Austin Chalk formation in La Salle County, Texas and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(6) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(7) Some of the same leases cover the net acres shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the net acreage for both formations is not equal to the total net acreage for Northwest Louisiana. This total includes acreage that we are producing from or that we believe to be prospective for these formations.

We are active both as an operator and as a co-working interest owner with various industry participants. At December 31, 2019, we operated the majority of our acreage in the Delaware Basin in Southeast New Mexico and West Texas. In those wells where we are not the operator, our working interests are often relatively small. At December 31, 2019, we also were the operator for approximately 93% of our Eagle Ford acreage and approximately 59% of our Haynesville acreage, including approximately 26% of our acreage in what we believe is the core area of the Haynesville play. A large portion of our acreage in the core area of the Haynesville shale is operated by Chesapeake.

While we do not always have direct access to our operating partners' drilling plans with respect to future well locations on non-operated properties, we do attempt to maintain ongoing communications with the technical staff of these operators in an effort to understand their drilling plans for purposes of our capital expenditure budget and our booking of any related proved undeveloped well locations and reserves. We review these locations with Netherland, Sewell & Associates, Inc., independent reservoir engineers, on a periodic basis to ensure their concurrence with our estimates of these drilling plans and our approach to booking these reserves.

Southeast New Mexico and West Texas — Delaware Basin

The greater Permian Basin in Southeast New Mexico and West Texas is a mature exploration and production region with extensive developments in a wide variety of petroleum systems resulting in stacked target horizons in many areas. Historically, the majority of development in this basin has focused on relatively conventional reservoir targets, but the combination of advanced formation evaluation, 3-D seismic technology, horizontal drilling and hydraulic fracturing technology is enhancing the development potential of this basin, particularly in the organic rich shales, or source rocks, of the Wolfcamp formation and in the low permeability sand and carbonate reservoirs of the Bone Spring, Avalon and Delaware formations.

In the western part of the Permian Basin, also known as the Delaware Basin, the Lower Permian age Bone Spring (also called the Leonardian) and Wolfcamp formations are several thousand feet thick and contain stacked layers of shales, sandstones, limestones and dolomites. These intervals represent a complex and dynamic submarine depositional system that also includes organic rich shales that are the source rocks for oil and natural gas produced in the basin. Historically, production has come from conventional reservoirs; however, we and other industry players have realized that the source rocks also have sufficient porosity and permeability to be commercial reservoirs. In addition, the source rocks are interbedded with reservoir layers that have filled with hydrocarbons, both of which can produce significant volumes of oil and natural gas when connected by horizontal wellbores with multi-stage hydraulic fracture treatments. Particularly in the Delaware Basin, there are multiple horizontal targets in a given area that exist within the several thousand feet of hydrocarbon bearing layers that make up the Bone Spring and Wolfcamp plays. Multiple horizontal drilling and completion targets are being identified and targeted by companies, including us, throughout the vertical section, including the Brushy Canyon, Avalon, Bone Spring (First, Second and Third Sand) and several intervals within the Wolfcamp shale, often identified as Wolfcamp A through D.

At December 31, 2019, our total acreage position in Southeast New Mexico and West Texas was approximately 231,300 gross (128,200 net) acres, primarily in Loving County, Texas and Lea and Eddy Counties, New Mexico. These acreage totals included approximately 36,400 gross (19,500 net) acres in our Ranger asset area in Lea County, 61,900 gross (26,300 net) acres in our Arrowhead asset area in Eddy County, 44,000 gross (25,000 net) acres in our Rustler Breaks asset area in Eddy County, 24,200 gross (16,500 net) acres in our Antelope Ridge asset area in Lea County, 15,000 gross (10,800 net) acres in our Wolf and Jackson Trust asset areas in Loving County, 2,800 gross (2,800 net) acres in our Stateline asset area in Eddy County and 46,400 gross (26,800 net) acres in our Twin Lakes asset area in Lea County at December 31, 2019. We consider the vast majority of our Delaware Basin acreage position to be prospective for oil and liquids-rich targets in the Bone Spring and Wolfcamp formations. Other potential targets on certain portions of our acreage include the Avalon and Delaware formations, as well as the Abo, Strawn, Devonian, Penn Shale, Atoka and Morrow formations. At December 31, 2019, our acreage position in the Delaware Basin was approximately 59% held by existing production. Excluding the Twin Lakes asset area, where we have drilled only three vertical operated wells and two horizontal operated wells, and the undeveloped acreage acquired in the BLM New Mexico Oil and Gas Lease Sale on September 5 and 6, 2018 (the "BLM Acquisition"), which has 10-year leases with favorable lease-holding provisions, our acreage position in the Delaware Basin was approximately 73% held by existing production at December 31, 2019.

During the year ended December 31, 2019, we continued the delineation and development of our Delaware Basin acreage. We completed and began producing oil and natural gas from 138 gross (65.7 net) wells in the Delaware Basin, including 76 gross (61.4 net) operated wells and 62 gross (4.3 net) non-operated wells, throughout our various asset areas. At December 31, 2019, we had tested a number of different producing horizons at various locations across our acreage position, including the Brushy Canyon, the Avalon, the First Bone Spring, two benches of the Second Bone Spring, the Third Bone Spring, three benches of the Wolfcamp A, including the X and Y sands and the more organic, lower section of the Wolfcamp A, three benches of the Wolfcamp B, the Wolfcamp D, the Morrow and the Strawn. Most of our delineation and development efforts have been focused on multiple completion targets between the First Bone Spring and the Wolfcamp B.

As a result of our ongoing drilling and completion operations in these asset areas, our Delaware Basin production increased significantly in 2019. Our average daily oil equivalent production from the Delaware Basin increased approximately 23% to 55,599 BOE per day (84% of total oil equivalent production), including 35,184 Bbl of oil per day (92% of total oil production) and 122.5 MMcf of natural gas per day (73% of total natural gas production), in 2019, as compared to 45,237 BOE per day (87% of total oil equivalent production), including 28,026 Bbl of oil per day (92% of total oil production) and 103.3 MMcf of natural gas per day (80% of total natural gas production), in 2018. Our average daily oil equivalent production from the Delaware Basin also grew approximately 25% from 49,309 BOE per day in the fourth quarter of 2018 to 61,493 BOE per day in the fourth quarter of 2019.

At December 31, 2019, approximately 92% of our estimated total proved oil and natural gas reserves, or 232.8 million BOE, was attributable to the Delaware Basin, including approximately 139.6 million Bbl of oil and 559.2 Bcf of natural gas, a 22% increase, as compared to 191.5 million BOE for the year ended December 31, 2018. Our Delaware Basin proved reserves at December 31, 2019 comprised approximately 94% of our proved oil reserves and 89% of our proved natural gas reserves, as compared to approximately 93% of our proved oil reserves and 83% of our proved natural gas reserves at December 31, 2018.

At December 31, 2019, we had identified 5,287 gross (2,332.4 net) engineered locations for potential future drilling on our Delaware Basin acreage, primarily in the Wolfcamp or Bone Spring plays, but also including the shallower Brushy Canyon and Avalon formations and the deeper Strawn formation. These locations include 3,290 gross (2,139.7 net) locations that we anticipate operating as we hold a working interest of at least 25% in each of these locations. Each horizontal drilling location generally represents a one-mile lateral, although we anticipate that many of our future wells will have lateral lengths longer than one mile. These engineered locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our Delaware Basin wells and other nearby wells based on available public data, drilling densities anticipated on our properties and properties of other operators, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other criteria. Our engineered well locations at December 31, 2019 do not yet include all portions of our acreage position and do not include any horizontal locations in our Twin Lakes asset area in Lea County, New Mexico. Our identified well locations presume that multiple intervals may be prospective at any one surface location. Although we believe that denser well spacing may be possible in certain asset areas or in certain formations, at December 31, 2019, the majority of our estimated locations were based on the assumption of 160-acre well spacing. As we explore and develop our Delaware Basin acreage further, we anticipate that we may identify additional locations for future drilling. At December 31, 2019, these potential future drilling locations included 372 gross (168.5 net) locations in the Delaware Basin, primarily in the Wolfcamp and Bone Spring plays, but also in the Brushy Canyon, Avalon, Delaware and Strawn formations, to which we have assigned proved undeveloped reserves, and certain of these locations to which we have assigned proved undeveloped reserves may contemplate lateral lengths longer than one mile.

At December 31, 2019, we were operating six drilling rigs in the Delaware Basin, and we expect to operate six rigs in the Delaware Basin throughout 2020, including two to four rigs (at times) in the Stateline asset area, one to two rigs (at times) in the Rustler Breaks asset area, one to two rigs (at times) in the Antelope Ridge asset area, one rig in the Wolf and Jackson Trust asset areas and one rig in the Greater Stebbins Area in the southern Arrowhead asset area. We have continued to build significant optionality into our drilling program. Three of our rigs operate on longer-term contracts with remaining average terms of approximately 19 months. The other three rigs are on short-term contracts with remaining obligations of less than twelve months. This affords us the ability to modify our drilling program as we may deem necessary based on changing commodity prices and other factors. We are also planning to participate in non-operated wells in the Delaware Basin as these opportunities arise in 2020.

Rustler Breaks Asset Area - Eddy County, New Mexico

We operated one to two drilling rigs in our Rustler Breaks asset area during most of 2019. We completed and turned to sales 48 gross (16.7 net) horizontal wells and one gross (1.0 net) vertical well in the Rustler Breaks asset area in 2019, including 19 gross (14.4 net) operated and 30 gross (3.3 net) non-operated wells.

The Garrett #111H well was particularly significant, being our first operated test of the First Bone Spring formation in the Rustler Breaks asset area. This well, a one-mile lateral, tested 2,042 BOE per day (75% oil) during a 24-hour IP test in the third quarter of 2019. A second operated test of the First Bone Spring in the fourth quarter of 2019, the Paul #111H, tested 1,793 BOE per day (81% oil) during a 24-hour IP test. We believe these two wells demonstrate the prospectivity of the First Bone Spring formation in the Rustler Breaks asset area.

We were also pleased with the results from our Wolfcamp wells turned to sales in 2019 in the Rustler Breaks asset area. In particular, the General Kehoe wells in the eastern portion of the asset area were drilled and completed as part of a five-well batch from a single pad and contributed significantly to our better-than-expected oil and natural gas production in the second half of 2019.

Wolf and Jackson Trust Asset Areas - Loving County, Texas

In the Wolf and Jackson Trust asset areas, we continued to focus primarily on the Wolfcamp A-XY and Wolfcamp A-Lower formations in 2019. We operated one drilling rig in our Wolf and Jackson Trust asset areas during 2019, and we completed and turned to sales 11 gross (7.8 net) horizontal wells in these asset areas, including ten gross (7.8 net) operated wells and one gross (less than 0.1 net) non-operated well. Most of these wells were completed in the Wolfcamp A-XY interval.

We continued to experience success with longer laterals (greater than one mile) we drilled in the Wolf asset area in 2019. For example, the Howard Posner 83-TTT-B33 WF #203H and #204H (Howard Posner #203H and #204H) wells, both Wolfcamp A-XY completions, tested 2,382 BOE per day (58% oil) and 1,813 BOE per day (60% oil), respectively, during 24-hour IP tests. Both the Howard Posner #203H and #204H wells had completed lateral lengths of approximately 7,500 feet.

Arrowhead, Ranger and Twin Lakes Asset Areas - Eddy and Lea Counties, New Mexico

We operated one drilling rig in our Arrowhead, Ranger and Twin Lakes asset areas during 2019. We completed and turned to sales 20 gross (11.3 net) horizontal wells and two gross (2.0 net) vertical wells in the Arrowhead, Ranger and Twin Lakes asset areas in 2019, including 17 gross (13.0 net) operated and five gross (0.3 net) non-operated wells. Most of these wells were completed in the Second Bone Spring and Third Bone Spring intervals.

Following our initial test of the Wolfcamp A-XY in the third quarter of 2018, we were pleased with our continued delineation of the Wolfcamp A-XY in the Arrowhead asset area in 2019. In the third quarter of 2019, we completed and placed on production the Stebbins 19 Federal Com #203H and #204H wells. These wells tested 2,815 BOE per day (73% oil) and 2,262 BOE per day (75% oil), respectively, during 24-hour IP tests. We believe these results provided further evidence of Wolfcamp A-XY prospectivity moving north in the Delaware Basin.

Antelope Ridge Asset Area - Lea County, New Mexico

We operated one to two drilling rigs in our Antelope Ridge asset area during 2019. We completed and turned to sales 55 gross (25.9 net) horizontal wells and one gross (1.0 net) vertical well in this asset area in 2019, including 30 gross (26.2 net) operated and 26 gross (0.7 net) non-operated wells. As we continued to delineate the Antelope Ridge asset area during 2019, we tested six different intervals, completing wells in the Brushy Canyon, First, Second and Third Bone Spring, Wolfcamp A-XY and Wolfcamp A-Lower.

A key achievement in our Antelope Ridge asset area in 2019 was the drilling and completion of our first two operated two-mile horizontal wells in the asset area—the Jeff Hart #124H and #134H wells, Second Bone Spring and Third Bone Spring completions, respectively. The Jeff Hart #124H and #134H wells tested 2,332 BOE per day (81% oil) and 2,884 BOE per day (90% oil), respectively, during 24-hour IP tests in the third quarter of 2019. The Jeff Hart #134H well produced approximately 70,000 Bbl of oil in its first 30 days of production, which is the highest 30-day cumulative oil production for any well drilled and completed by us, including our prolific Mallon wells in the Ranger asset area, also Third Bone Spring completions. Further, drilling and completion costs on the Jeff Hart #134H well were just under $1,000 per lateral foot, about 20% to 25% below the drilling and completion costs per lateral foot associated with one-mile laterals we previously drilled in the Antelope Ridge asset area. In their first five months of production, the Jeff Hart #124H and #134H wells each produced more than 200,000 Bbl of oil in its first 150 days of production. The early production from these wells has more than doubled that of our nearby one-mile lateral completions over a similar timeframe, and these wells continued to exhibit a shallower initial production decline as compared to nearby one-mile laterals drilled by us.

In addition, we were particularly pleased with our delineation of the Wolfcamp A formation in the Antelope Ridge asset area. The Brad Lummis Com #212H well, a Wolfcamp A-XY completion, flowed at 3,236 BOE per day (83% oil) during its 24-hour IP test, or over 700 BOE per 1,000 feet of completed lateral. This well result complemented those from the four Charles Ling wells completed and turned to sales in the Wolfcamp A-Lower formation late in the first quarter of 2019, which flowed at an average of 2,932 BOE per day (75% oil) during their respective 24-hour IP tests.

Additionally, we began drilling operations on the 1,200 gross and net acre Rodney Robinson tract in our western Antelope Ridge asset area in the third quarter of 2019. The Rodney Robinson tract is one of the key tracts we acquired in the BLM Acquisition. The acquired leases are federal leases and provide an 87.5% net revenue interest (“NRI”) as compared to approximately 75% NRI on most fee leases today. We drilled six initial wells on this tract from two separate three-well pads. These six wells, which are all two-mile laterals, are currently scheduled to be completed and turned to sales in late March 2020.

Stateline Asset Area - Eddy County, New Mexico

In early September 2018, we acquired the Stateline asset area in southern Eddy County, New Mexico as part of the BLM Acquisition. The Stateline asset area includes approximately 2,800 gross and net undeveloped leasehold acres prospective for multiple geologic targets. The acquired leases are federal leases and provide an 87.5% NRI. The large majority of the acquired acreage is believed to be conducive to drilling longer laterals of up to two miles or more, utilizing central facilities and multi-well pad development. We began drilling operations in the Stateline asset area just before the end of 2019 and, at February 25, 2020, had two of our drilling rigs operating there. We plan to develop this acreage block drilling two-mile laterals on the eastern side of the leasehold and approximately 2.5-mile laterals on the western side of the leasehold. We initially expect to drill 13 wells on the eastern portion of this leasehold, and these 13 wells are expected to be completed and turned to sales late in third quarter of 2020 in conjunction with the expected completion of the expansion of the Black River Processing Plant by San Mateo. We anticipate running at least two rigs full-time in the Stateline asset area for the foreseeable future.

South Texas — Eagle Ford Shale and Other Formations

The Eagle Ford shale extends across portions of South Texas from the Mexican border into East Texas forming a band roughly 50 to 100 miles wide and 400 miles long. The Eagle Ford is an organically rich calcareous shale and lies between the deeper Buda limestone and the shallower Austin Chalk formation. Along the entire length of the Eagle Ford trend, the structural dip of the formation is consistently down to the south with relatively few, modestly sized structural perturbations. As a result, depth of burial increases consistently southwards along with the thermal maturity of the formation. Where the Eagle Ford is shallow, it is less thermally mature and therefore more oil prone, and as it gets deeper and becomes more thermally mature, the Eagle Ford is more natural gas prone. The transition between being more oil prone and more natural gas prone includes an interval that typically produces liquids-rich natural gas with condensate.

At December 31, 2019, our properties included approximately 31,200 gross (28,400 net) acres in the Eagle Ford shale play in Atascosa, DeWitt, Gonzales, Karnes, La Salle, Wilson and Zavala Counties in South Texas. We believe that approximately 88% of our Eagle Ford acreage is prospective predominantly for oil or liquids-rich natural gas with condensate, with the remainder being prospective for less liquids-rich natural gas. Approximately 93% of our Eagle Ford acreage was held by production at December 31, 2019.

In October 2018, we commenced a drilling program in South Texas to drill nine wells, primarily in the Eagle Ford shale, to take advantage of higher oil and natural gas prices in South Texas, to conduct at least one exploratory test of the Austin Chalk formation and to validate and hold by production almost all of our remaining undeveloped acreage in South Texas. One of the Eagle Ford shale wells was completed and turned to sales during the fourth quarter of 2018, and the remaining eight gross (7.9 net) wells, including one well drilled in the Austin Chalk formation, were completed and turned to sales in the first half of 2019.

Two of these wells, the Lloyd Hurt C #12H and D #13H wells, which targeted the Eagle Ford shale, flowed an average of 1,085 BOE per day (85% oil), including 923 Bbl of oil per day and 1.0 MMcf of natural gas per day, during 24-hour IP tests from completed lateral lengths of approximately 8,800 feet. These wells marked the two best 24-hour IP test results from any Eagle Ford wells we have completed to date in our far northwest La Salle County acreage. In addition, the Lloyd Hurt AC-C #26H well, an Austin Chalk completion, tested approximately 600 BOE per day (93% oil) during a 24-hour IP test conducted following the installation of an electric submersible pump ("ESP") in the wellbore. We were encouraged by this initial test and the early results from the Austin Chalk formation in far northwest La Salle County, where almost no horizontal completions of the Austin Chalk formation using modern drilling and stimulation technology had been previously attempted.

Primarily as a result of the initial production from this nine-well program, our average daily oil equivalent production from the Eagle Ford shale increased 27% to 4,009 BOE per day, including 3,113 Bbl of oil per day and 5.4 MMcf of natural gas per day, during 2019, as compared to 3,158 BOE per day, including 2,485 Bbl of oil per day and 4.0 MMcf of natural gas per day, during 2018. For the year ended December 31, 2019, 6% of our total daily oil equivalent production was attributable to the Eagle Ford shale, as compared to 6% for the year ended December 31, 2018.

At December 31, 2019, approximately 4% of our estimated total proved oil and natural gas reserves, or 11.2 million BOE, was attributable to the Eagle Ford shale, including approximately 8.4 million Bbl of oil and 17.2 Bcf of natural gas. Our Eagle Ford total proved reserves comprised approximately 6% of our proved oil reserves and 3% of our proved natural gas reserves at December 31, 2019, as compared to approximately 7% of our proved oil reserves and 4% of our proved natural gas reserves at December 31, 2018.

At December 31, 2019, we had identified 234 gross (196.3 net) engineered locations for potential future drilling on our Eagle Ford acreage. These locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our producing Eagle Ford wells and other nearby wells based on available public data, drilling densities anticipated on our properties and observed on properties of other operators, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other factors. The identified well locations presume that we will be able to develop our Eagle Ford properties on 40- to 80-acre spacing, depending on the specific property and the wells we have already drilled. We anticipate that any Eagle Ford wells drilled on our acreage in central and northern La Salle, northern Karnes and southern Wilson Counties can be developed on 40- to 50-acre spacing, while other properties, particularly the eastern portion of our acreage in DeWitt County, are more likely to be developed on 80-acre spacing. At December 31, 2019, these 234 gross (196.3 net) identified drilling locations included 14 gross (13.7 net) locations to which we have assigned proved undeveloped reserves.

These engineered drilling locations include only a single interval in the lower portion of the Eagle Ford shale. We believe portions of our Eagle Ford acreage may be prospective for an additional target in the lower portion of the Eagle Ford shale and for other intervals in the upper portion of the Eagle Ford shale, from which we would expect to produce predominantly oil and liquids. In addition, we believe portions of our Eagle Ford acreage may also be prospective for the Austin Chalk, Buda and other formations, from which we would expect to produce predominantly oil and liquids. At December 31, 2019, we had not included any future drilling locations in the upper portion of the Eagle Ford shale, in any additional intervals of the lower portion of the Eagle Ford shale or in the Austin Chalk or Buda formations, even though activity from other operators in these formations around our South Texas acreage position has demonstrated the potential prospectivity of these intervals.

Northwest Louisiana — Haynesville Shale, Cotton Valley and Other Formations

The Haynesville shale is an organically rich, overpressured marine shale found below the Cotton Valley and Bossier formations and above the Smackover formation at depths ranging from 10,500 to 13,500 feet across a broad region throughout Northwest Louisiana, including principally Bossier, Caddo, DeSoto and Red River Parishes in Louisiana. The Haynesville shale produces primarily dry natural gas with almost no associated liquids. The Bossier shale is overpressured and is often divided into lower, middle and upper units. The Cotton Valley formation is a low permeability natural gas sand that ranges in thickness from 200 to 300 feet and has porosity ranging from 6% to 10%.

We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana during 2019, although we did participate in the drilling and completion of 26 gross (1.7 net) non-operated Haynesville shale wells that were turned to sales in 2019, the most significant of which were two gross (1.0 net) two-mile lateral wells drilled and completed by Chesapeake in the third quarter of 2019. These two wells, the LDW&F 15&10-14-12 HC001-ALT and HC002-ALT wells, were located in the southern part of our Elm Grove asset area in the core of the Haynesville shale play and tested 38.4 and 42.4 MMcf of natural gas per day, respectively, during 24-hour IP tests, and these wells contributed to our natural gas production growth in the second half of 2019. We do not plan to drill any operated Haynesville shale or Cotton Valley wells in 2020.

At December 31, 2019, we held approximately 19,700 gross (18,300 net) acres in Northwest Louisiana, including 17,500 gross (10,000 net) acres in the Haynesville shale play and 16,100 gross (14,900 net) acres in the Cotton Valley play. We operate substantially all of our Cotton Valley and shallower production on our leasehold interests in Northwest Louisiana, as well as all of our Haynesville production on the acreage outside of what we believe to be the core area of the Haynesville shale play. We operate approximately 26% of the 12,400 gross (5,600 net) acres that we consider to be in the core area of the Haynesville shale play.

For the year ended December 31, 2019, approximately 10% of our average daily oil equivalent production, or 6,595 BOE per day, including 15 Bbl of oil per day and 39.5 MMcf of natural gas per day, was attributable to our leasehold interests in Northwest Louisiana. Natural gas production from these properties comprised approximately 24% of our daily natural gas production during 2019, as compared to approximately 17% of our daily natural gas production during 2018. During the year ended December 31, 2018, approximately 7% of our average daily oil equivalent production, or 3,733 BOE per day, including 13 Bbl of oil per day and 22.3 MMcf of natural gas per day, was attributable to our properties in Northwest Louisiana and East Texas.

For the year ended December 31, 2019, approximately 23% of our daily natural gas production, or 38.1 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 1%, or 1.4 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties. For the year ended December 31, 2018, approximately 16% of our daily natural gas production, or 20.5 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 1%, or 1.8 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties. At December 31, 2019, approximately 3% of our estimated total proved reserves, or 7.7 million BOE, was attributable to the Haynesville shale with another 0.3% of our proved reserves, or 0.9 million BOE, attributable to the Cotton Valley and shallower formations underlying this acreage.

At December 31, 2019, we had identified 341 gross (80.8 net) engineered locations for potential future drilling in the Haynesville shale play and 70 gross (48.3 net) engineered locations for potential future drilling in the Cotton Valley formation. Each horizontal drilling location generally assumes a one-mile lateral, although we anticipate that many of our future wells may have lateral lengths longer than one mile. These locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our producing Haynesville and Cotton Valley wells and other nearby wells based on available public data, drilling densities observed on properties of other operators, including on some of our non-operated properties, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface conditions, among other criteria. Of the 341 gross (80.8 net) locations identified for future drilling on our Haynesville acreage, 277 gross (37.8 net) locations have been identified within the 12,400 gross (5,600 net) acres that we believe are located in the core area of the Haynesville shale play. As we explore and develop our Northwest Louisiana acreage further, we believe it is possible that we may identify additional locations for future drilling. At December 31, 2019, these potential future drilling locations included 5 gross (0.5 net) locations in the Haynesville shale (and no locations in the Cotton Valley) to which we have assigned proved undeveloped reserves.

MIDSTREAM SEGMENT

Our midstream segment conducts midstream operations in support of our exploration, development and production operations and provides natural gas processing, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties.

Southeast New Mexico and West Texas — Delaware Basin

On February 17, 2017, we announced the formation of San Mateo I, a strategic joint venture with a subsidiary of Five Point. The midstream assets that were contributed to San Mateo I included (i) the Black River Processing Plant; (ii) one salt water disposal well and a related commercial salt water disposal facility in the Rustler Breaks asset area; (iii) three salt water disposal wells and related commercial salt water disposal facilities in the Wolf asset area and (iv) substantially all related oil, natural gas and salt water gathering systems and pipelines in both the Rustler Breaks and Wolf asset areas (collectively, the "Delaware Midstream Assets"). We received $171.5 million in connection with the formation of San Mateo I and had the potential to earn up to $73.5 million in performance incentives over a five-year period. At February 28, 2020, we had received $44.1 million of the potential $73.5 million in performance incentives. We may earn up to the remaining $29.4 million in San Mateo I performance incentives over the next two years. We continue to operate the Delaware Midstream Assets and retain operational control of San Mateo I. The Company and Five Point own 51% and 49% of San Mateo I, respectively. San Mateo I continues to provide firm service to us, while also being a midstream service provider to other customers in and around our Wolf and Rustler Breaks asset areas.

On February 25, 2019, we announced the formation of San Mateo II, a strategic joint venture with a subsidiary of Five Point designed to expand our midstream operations in the Delaware Basin, specifically in Eddy County, New Mexico. San Mateo II is owned 51% by us and 49% by Five Point. In addition, Five Point has committed to pay $125.0 million of the first $150.0 million of capital expenditures incurred by San Mateo II to develop facilities in the Greater Stebbins Area and the Stateline asset area. We have the ability to earn up to $150.0 million in deferred performance incentives over the next several years, plus additional performance incentives for securing volumes from third-party customers.

In connection with the formation of San Mateo II, we dedicated to San Mateo II acreage in the Greater Stebbins Area and the Stateline asset area pursuant to 15-year, fixed-fee agreements for oil, natural gas and salt water gathering, natural gas processing and salt water disposal. San Mateo II provides firm service to us in the Greater Stebbins Area and the Stateline asset area.

Natural Gas Gathering and Processing Assets

The Black River Processing Plant and associated gathering system were originally built to support our ongoing and future development efforts in the Rustler Breaks asset area and to provide us with firm takeaway and processing services for our Rustler Breaks natural gas production. We had previously completed the installation and testing of a 12-inch natural gas trunk line and associated gathering lines running throughout the length of our Rustler Breaks acreage position, and these natural gas gathering lines are being used to gather almost all of our operated natural gas production at Rustler Breaks.

During 2019, as part of the San Mateo II expansion, San Mateo began expanding the Black River Processing Plant in our Rustler Breaks asset area in Eddy County, New Mexico to add an incremental designed inlet capacity of 200 MMcf of natural gas per day to the existing designed inlet capacity of 260 MMcf of natural gas per day, bringing the total designed inlet capacity to 460 MMcf of natural gas per day. This expansion is anticipated to be placed in service during the summer of 2020. In addition, San Mateo initiated plans in 2019 to construct large diameter natural gas gathering lines southward from the Greater Stebbins Area and northward from the Stateline asset area to connect these areas with the Black River Processing Plant. The expanded Black River Processing Plant supports our exploration and production development activities in the Delaware Basin and offers processing opportunities for other producers' development efforts.

During 2019, San Mateo received an increased natural gas gathering and processing commitment from an existing natural gas customer, plus other interruptible volumes. At certain times near the end of the third quarter and early in the fourth quarter of 2019, as a result of increased throughput from existing natural gas processing customers, San Mateo was operating the Black River Processing Plant at greater than 95% of the current designed inlet capacity of 260 MMcf per day.

In October 2018, a subsidiary of San Mateo entered into a long-term agreement with a significant producer in Eddy County, New Mexico relating to the gathering and processing of such producer's natural gas production. As a result of this agreement, along with prior natural gas gathering and processing agreements entered into by San Mateo with its customers, including us, at December 31, 2019, San Mateo had entered into contracts to provide firm gathering and processing services for over 200 MMcf of natural gas per day, or over 80% of the designed inlet capacity of 260 MMcf of natural gas per day, at the Black River Processing Plant.

In addition, in early 2018, San Mateo completed a natural gas liquids ("NGL") pipeline connection at the Black River Processing Plant to the NGL pipeline owned by EPIC Y-Grade Pipeline LP. This NGL connection provides several significant benefits to us and other San Mateo customers compared to transporting the NGLs by truck. San Mateo's customers receive (i) firm NGL takeaway out of the Delaware Basin, (ii) increased NGL recoveries, (iii) improved pricing realizations through lower transportation and fractionation costs and (iv) increased optionality through San Mateo's ability to operate the Black River Processing Plant in ethane recovery mode, if desired.

In our Wolf asset area in Loving County, Texas, San Mateo gathers our natural gas production with the natural gas gathering system we retained following the sale of our wholly-owned subsidiary that owned certain natural gas gathering and processing assets in the Wolf asset area (the "Loving County Processing System") to an affiliate of EnLink Midstream Partners, LP ("EnLink") in October 2015. The Loving County Processing System included a cryogenic natural gas processing plant (the "Wolf Processing Plant") and approximately six miles of high-pressure gathering pipeline that connected our gathering system to the Wolf Processing Plant. Substantially all of our remaining midstream assets in the Wolf asset area were contributed to San Mateo I in February 2017.

At December 31, 2019, San Mateo's natural gas gathering systems included natural gas gathering pipelines and related compression and treating systems. During the year ended December 31, 2019, San Mateo gathered approximately 77.2 Bcf of natural gas, as compared to 46.1 Bcf of natural gas gathered during the year ended December 31, 2018. In addition, during the year ended December 31, 2019, San Mateo processed approximately 64.7 Bcf of natural gas at the Black River Processing Plant, as compared to 32.3 Bcf of natural gas processed during the year ended December 31, 2018.

Crude Oil Gathering and Transportation Assets

Subsidiaries of San Mateo and Plains All American Pipeline, L.P. ("Plains") have entered into a strategic relationship to gather and transport crude oil for upstream producers in Eddy County, New Mexico and have agreed to work together through a joint tariff arrangement and related transactions to offer producers located within the Joint Development Area crude oil transportation services from the wellhead to Midland, Texas with access to other end markets.

San Mateo completed its expanded oil gathering system in the Wolf asset area in Loving County, Texas (the "Wolf Oil Pipeline System") in May 2018 and placed into service its crude oil gathering and transportation system in the Rustler Breaks asset area in Eddy County, New Mexico (the "Rustler Breaks Oil Pipeline System") in December 2018. With the Wolf Oil Pipeline System and the Rustler Breaks Oil Pipeline System (collectively, the "San Mateo Oil Pipeline Systems") in service, at December 31, 2019, we estimated we had on pipe almost all of our oil production from the Wolf and Rustler Breaks asset areas, which comprised approximately 56% of our Delaware Basin oil production in 2019. With the San Mateo Oil Pipeline Systems in service, we improved our oil price realizations in the Wolf and Rustler Breaks asset areas through the elimination of higher priced trucking services.

At December 31, 2019, the San Mateo Oil Pipeline Systems included crude oil gathering and transportation pipelines from origin points in Loving County, Texas and Eddy County, New Mexico to interconnects with Plains Pipeline, L.P. and two trucking facilities. During the year ended December 31, 2019, the San Mateo Oil Pipeline Systems had throughput of approximately 8.9 million Bbl of oil, as compared to 2.0 million Bbl of oil throughput during the year ended December 31, 2018.

Produced Water Gathering and Disposal Assets

During 2019, San Mateo placed into service two commercial salt water disposal wells in the Rustler Breaks asset area and, at February 25, 2020, expected to place into service one additional salt water disposal well in the Rustler Breaks asset area late in the first quarter of 2020, bringing San Mateo's commercial salt water disposal well count in the Rustler Breaks asset area to eight. In the Greater Stebbins Area, San Mateo also acquired an existing commercial salt water disposal well and facility and surface acreage and subsequently placed into service an additional commercial salt water disposal well. In addition to its eight commercial salt water disposal wells and associated facilities in the Rustler Breaks asset area and its two commercial salt water disposal wells and associated facilities in the Greater Stebbins Area, at February 25, 2020, San Mateo had three commercial salt water disposal wells and associated facilities in the Wolf asset area, and San Mateo's salt water gathering systems included salt water gathering pipelines in the Rustler Breaks and Wolf asset areas and the Greater Stebbins Area. At February 25, 2020, San Mateo expected to have a designed disposal capacity of approximately 335,000 Bbl of salt water per day by the end of the first quarter of 2020.

In June 2018, a subsidiary of San Mateo entered into a long-term agreement with a significant producer in Eddy County, New Mexico to gather and dispose of the customer's produced salt water. The agreement includes the dedication of certain of the third party's wells, which are or will be located near San Mateo's existing salt water gathering system in Eddy County, New Mexico. In the first half of 2019, San Mateo obtained a significant additional acreage dedication and a salt water disposal well permit from another existing salt water disposal customer.

During the year ended December 31, 2019, San Mateo gathered approximately 69.9 million Bbl of salt water, as compared to 44.0 million Bbl of salt water gathered during the year ended December 31, 2018. In addition, during the year ended December 31, 2019, San Mateo disposed of approximately 67.1 million Bbl of salt water, as compared to 47.5 million Bbl of salt water disposed of during the year ended December 31, 2018.

South Texas / Northwest Louisiana

In South Texas, we own a natural gas gathering system that gathers natural gas production from certain of our operated Eagle Ford leases. In Northwest Louisiana, we have midstream assets that gather and treat natural gas from most of our operated leases and from third parties and four non-commercial salt water disposal wells that dispose of our salt water. Our midstream assets in South Texas and Northwest Louisiana are not part of San Mateo.

OPERATING SUMMARY

The following table sets forth certain unaudited production and operating data for the years ended December 31, 2019, 2018 and 2017.

	Year Ended December 31,		
	2019	2018	2017
Unaudited Production Data:			
Net Production Volumes:			
Oil (MBbl)	13,984	11,141	7,851
Natural gas (Bcf)	61.1	47.3	38.2
Total oil equivalent (MBOE) (1)	24,164	19,026	14,212
Average daily production (BOE/d) (1)	66,203	52,128	38,936
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$ 54.34	$ 57.04	$ 49.28
Oil, with realized derivatives (per Bbl)	$ 54.98	$ 57.38	$ 48.81
Natural gas, without realized derivatives (per Mcf)	$ 2.17	$ 3.49	$ 3.72
Natural gas, with realized derivatives (per Mcf)	$ 2.18	$ 3.46	$ 3.70
Operating Expenses (per BOE):			
Production taxes, transportation and processing	$ 3.82	$ 4.00	$ 4.10
Lease operating	$ 4.85	$ 4.89	$ 4.74
Plant and other midstream services operating	$ 1.52	$ 1.29	$ 0.92
Depletion, depreciation and amortization	$ 14.51	$ 13.94	$ 12.49
General and administrative	$ 3.31	$ 3.64	$ 4.65

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2019 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/ West Texas	South Texas	Northwest Louisiana		
	Delaware Basin	Eagle Ford (1)	Haynesville	Cotton Valley (2)	Total
Annual Net Production Volumes					
Oil (MBbl)	12,843	1,136	—	5	13,984
Natural gas (Bcf)	44.7	2.0	13.9	0.5	61.1
Total oil equivalent (MBOE) (3)	20,294	1,463	2,316	91	24,164
Percentage of total annual net production	84.0%	6.0%	9.6%	0.4%	100.0%
Average Net Daily Production Volumes					
Oil (Bbl/d)	35,184	3,113	—	15	38,312
Natural gas (MMcf/d)	122.5	5.4	38.1	1.4	167.4
Total oil equivalent (BOE/d)	55,599	4,009	6,345	250	66,203
Average Sales Prices (4)					
Oil (per Bbl)	$ 53.95	$58.71	$ —	$52.89	$ 54.34
Natural gas (per Mcf)	$ 2.11	$ 3.45	$ 2.16	$ 2.17	$ 2.17
Total oil equivalent (per BOE)	$ 38.80	$50.22	$12.99	$15.22	$ 36.93
Production Costs (5)					
Lease operating, transportation and processing (per BOE)	$ 5.22	$15.27	$ 4.36	$22.43	$ 5.81

(1) Includes one well producing oil from the Austin Chalk formation in La Salle County, Texas and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(3) Production volumes reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Excludes impact of derivative settlements.

(5) Excludes plant and other midstream services operating expenses, ad valorem taxes and oil and natural gas production taxes.

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2018 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/ West Texas	South Texas	Northwest Louisiana		
	Delaware Basin	Eagle Ford [1]	Haynesville	Cotton Valley [2]	Total
Annual Net Production Volumes					
Oil (MBbl)	10,230	907	—	4	11,141
Natural gas (Bcf)	37.7	1.5	7.5	0.6	47.3
Total oil equivalent (MBOE) [3]	16,512	1,152	1,247	115	19,026
Percentage of total annual net production	86.8%	6.0%	6.6%	0.6%	100.0%
Average Net Daily Production Volumes					
Oil (Bbl/d)	28,026	2,485	—	13	30,524
Natural gas (MMcf/d)	103.3	4.0	20.5	1.8	129.6
Total oil equivalent (BOE/d)	45,237	3,158	3,417	316	52,128
Average Sales Prices [4]					
Oil (per Bbl)	$ 56.12	$ 67.4	$ —	$64.72	$ 57.04
Natural gas (per Mcf)	$ 3.55	$ 5.46	$ 2.85	$ 2.80	$ 3.49
Total oil equivalent (per BOE)	$ 42.88	$60.02	$17.09	$18.59	$ 42.08
Production Costs [5]					
Lease operating, transportation and processing (per BOE)	$ 4.79	$17.25	$ 5.41	$19.11	$ 5.68

(1) Includes one well producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(3) Production volumes reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Excludes impact of derivative settlements.

(5) Excludes plant and other midstream services operating expenses, ad valorem taxes and oil and natural gas production taxes.

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2017 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/ West Texas	South Texas	Northwest Louisiana		
	Delaware Basin	Eagle Ford (1)	Haynesville	Cotton Valley (2)	Total
Annual Net Production Volumes					
Oil (MBbl)	6,579	1,268	—	4	7,851
Natural gas (Bcf)	25.1	2.0	10.3	0.8	38.2
Total oil equivalent (MBOE) (3)	10,754	1,611	1,714	133	14,212
Percentage of total annual net production	75.7%	11.3%	12.1%	0.9%	100.0%
Average Net Daily Production Volumes					
Oil (Bbl/d)	18,023	3,475	—	12	21,510
Natural gas (MMcf/d)	68.6	5.6	28.3	2.1	104.6
Total oil equivalent (BOE/d)	29,463	4,413	4,697	363	38,936
Average Sales Prices (4)					
Oil (per Bbl)	$ 49.08	$50.29	$ —	$45.52	$ 49.28
Natural gas (per Mcf)	$ 4.03	$ 4.69	$ 2.83	$ 2.79	$ 3.72
Total oil equivalent (per BOE)	$ 39.41	$45.58	$16.96	$17.69	$ 37.20
Production Costs (5)					
Lease operating, transportation and processing (per BOE)	$ 5.80	$10.92	$ 4.21	$16.77	$ 6.29

(1) Includes one well producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(3) Production volumes reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Excludes impact of derivative settlements.

(5) Excludes plant and other midstream services operating expenses, ad valorem taxes and oil and natural gas production taxes.

Our total oil equivalent production of approximately 24.2 million BOE for the year ended December 31, 2019 increased 27% from our total oil equivalent production of approximately 19.0 million BOE for the year ended December 31, 2018. This increased production was primarily due to our delineation and development operations in the Delaware Basin throughout 2019 as well as from our nine-well program in South Texas concluded in the first half of 2019 and non-operated Haynesville shale wells completed and placed on production during the third quarter of 2019. Our average daily oil equivalent production for the year ended December 31, 2019 was 66,203 BOE per day, as compared to 52,128 BOE per day for the year ended December 31, 2018. Our average daily oil production for the year ended December 31, 2019 was 38,312 Bbl of oil per day, an increase of 26% from 30,524 Bbl of oil per day for the year ended December 31, 2018. Our average daily natural gas production for the year ended December 31, 2019 was 167.4 MMcf of natural gas per day, an increase of 29% from 129.6 MMcf of natural gas per day for the year ended December 31, 2018.

Our total oil equivalent production of approximately 19.0 million BOE for the year ended December 31, 2018 increased 34% from our total oil equivalent production of approximately 14.2 million BOE for the year ended December 31, 2017. This increased production was primarily due to our delineation and development operations in the Delaware Basin, which offset declining production in the Eagle Ford and Haynesville shales. Our average daily oil equivalent production for the year ended December 31, 2018 was 52,128 BOE per day, as compared to 38,936 BOE per day for the year ended December 31, 2017. Our average daily oil production for the year ended December 31, 2018 was 30,524 Bbl of oil per day, an increase of 42% from 21,510 Bbl of oil per day for the year ended December 31, 2017. Our average daily natural gas production for the year ended December 31, 2018 was 129.6 MMcf of natural gas per day, an increase of 24% from 104.6 MMcf of natural gas per day for the year ended December 31, 2017.

PRODUCING WELLS

The following table sets forth information relating to producing wells at December 31, 2019. Wells are classified as oil wells or natural gas wells according to their predominant production stream. We had an approximate average working interest of 78% in all wells that we operated at December 31, 2019. For wells where we are not the operator, our working interests range from less than 1% to approximately 52% and average approximately 10%. In the table below, gross wells are the total number of producing wells in which we own a working interest and net wells represent the total of our fractional working interests owned in the gross wells.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/West Texas:						
Delaware Basin (1)	634	298.6	123	55.4	757	354.0
South Texas:						
Eagle Ford (2)	139	117.4	4	4.0	143	121.4
Northwest Louisiana:						
Haynesville	—	—	246	20.5	246	20.5
Cotton Valley (3)	1	1.0	65	39.7	66	40.7
Area Total	1	1.0	311	60.2	312	61.2
Total	774	417.0	438	119.6	1,212	536.6

(1) Includes 218 gross (56.5 net) vertical wells that were acquired in multiple transactions.

(2) Includes one well producing oil from the Austin Chalk formation in La Salle County, Texas and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(3) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

ESTIMATED PROVED RESERVES

The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2019, 2018 and 2017. Our production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where we produce liquids-rich natural gas, such as in the Delaware Basin and the Eagle Ford shale, the economic value of the NGLs associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the NGLs are extracted and sold. The reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with SEC rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that could be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are the estimated quantities of crude oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

	At December 31,[1]		
	2019	2018	2017
Estimated Proved Reserves Data:[2]			
Estimated proved reserves:			
Oil (MBbl)	147,991	123,401	86,743
Natural Gas (Bcf)	627.2	551.5	396.2
Total (MBOE)[3]	252,531	215,313	152,771
Estimated proved developed reserves:			
Oil (MBbl)	59,667	53,223	36,966
Natural Gas (Bcf)	276.3	246.2	190.1
Total (MBOE)[3]	105,710	94,261	68,651
Percent developed	41.9%	43.8%	44.9%
Estimated proved undeveloped reserves:			
Oil (MBbl)	88,324	70,178	49,777
Natural gas (Bcf)	351.0	305.2	206.1
Total (MBOE)[3]	146,821	121,052	84,120
Standardized Measure[4] (in millions)	$ 2,034.0	$ 2,250.6	$ 1,258.6
PV-10[5] (in millions)	$ 2,248.2	$ 2,579.3	$ 1,333.4

(1) Numbers in table may not total due to rounding.

(2) Our estimated proved reserves, Standardized Measure and PV-10 were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the 12 months ended December 31, 2019 were $52.19 per Bbl for oil and $2.58 per MMBtu for natural gas, for the 12 months ended December 31, 2018 were $62.04 per Bbl for oil and $3.10 per MMBtu for natural gas and for the 12 months ended December 31, 2017 were $47.79 per Bbl for oil and $2.98 per MMBtu for natural gas. These prices were adjusted by lease for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead. We report our proved reserves in two streams, oil and natural gas, and the economic value of the NGLs associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the NGLs are extracted and sold.

(3) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

(5) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2019, 2018 and 2017 may be reconciled to our Standardized Measure of discounted future net cash flows at such dates by adding the discounted future income taxes associated with such reserves to the Standardized Measure. The discounted future income taxes at December 31, 2019, 2018 and 2017 were, in millions, $214.2, $328.7 and $74.8, respectively.

Our estimated total proved oil and natural gas reserves increased 17% from 215.3 million BOE at December 31, 2018 to 252.5 million BOE at December 31, 2019. We added 58.6 million BOE in proved oil and natural gas reserves through extensions and discoveries throughout 2019, approximately 2.4 times our 2019 annual production of 24.2 million BOE. Our proved oil reserves grew 20% from approximately 123.4 million Bbl at December 31, 2018 to approximately 148.0 million Bbl at December 31, 2019. Our proved natural gas reserves increased 14% from 551.5 Bcf at December 31, 2018 to 627.2 Bcf at December 31, 2019. This increase in proved oil and natural gas reserves was primarily a result of our delineation and development operations in the Delaware Basin during 2019. We realized approximately 5.1 million BOE in net upward revisions to our proved reserves during 2019 primarily as a result of upward technical revisions resulting from better-than-projected well performance from certain wells, as compared to December 31, 2018, and despite lower commodity prices used to estimate proved reserves at December 31, 2019. Our proved reserves to production ratio at December 31, 2019 was 10.5, a decrease of 7% from 11.3 at December 31, 2018.

Over the past two years, our estimated total proved oil and natural gas reserves increased 65% from 152.8 million BOE at December 31, 2017 to 252.5 million Bbl at December 31, 2019. Our proved oil reserves grew 71% from 86.7 million Bbl at December 31, 2017 to 148.0 million Bbl at December 31, 2019. Our proved developed oil reserves increased 61% from 37.0 million Bbl at December 31, 2017 to 59.7 million Bbl at December 31, 2019.

The Standardized Measure of our total proved oil and natural gas reserves decreased 10% from $2.25 billion at December 31, 2018 to $2.03 billion at December 31, 2019. The PV-10 of our total proved oil and natural gas reserves decreased 13% from $2.58 billion at December 31, 2018 to $2.25 billion at December 31, 2019. The decreases in our Standardized Measure and PV-10 are primarily a result of lower weighted average oil and natural gas prices used to estimate proved reserves at December 31, 2019, as compared to December 31, 2018. The unweighted arithmetic averages of first-day-of-the-month oil and natural gas prices used to estimate proved reserves at December 31, 2019 were $52.19 per Bbl and $2.58 per MMBtu, a decrease of 16% and 17%, respectively, as compared to average oil and natural gas prices of $62.04 per Bbl and $3.10 per MMBtu used to estimate proved reserves at December 31, 2018. Our total proved reserves were made up of 59% oil and 41% natural gas at December 31, 2019, as compared to 57% oil and 43% natural gas at December 31, 2018. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see the preceding table.

Our proved developed oil and natural gas reserves increased 12% from 94.3 million BOE at December 31, 2018 to 105.7 million BOE at December 31, 2019 due primarily to our delineation and development operations in the Delaware Basin. Our proved developed oil reserves increased 12% from 53.2 million Bbl at December 31, 2018 to 59.7 million Bbl at December 31, 2019. Our proved developed natural gas reserves increased 12% from 246.2 Bcf at December 31, 2018 to 276.3 Bcf at December 31, 2019.

The following table summarizes changes in our estimated proved developed reserves at December 31, 2019.

	Proved Developed Reserves (MBOE)[(1)]
As of December 31, 2018	94,261
Extensions and discoveries	14,206
Net divestitures of minerals-in-place	(736)
Revisions of prior estimates	(1,486)
Production	(24,164)
Conversion of proved undeveloped to proved developed	23,629
As of December 31, 2019	105,710

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Our proved undeveloped oil and natural gas reserves increased 21% from 121.1 million BOE at December 31, 2018 to 146.8 million BOE at December 31, 2019. Our proved undeveloped oil and natural gas reserves increased from 70.2 million Bbl and 305.2 Bcf, respectively, at December 31, 2018 to 88.3 million Bbl and 351.0 Bcf, respectively, at December 31, 2019, primarily as a result of our delineation and development operations in the Delaware Basin.

At December 31, 2019, we had no proved undeveloped reserves in our estimates that remained undeveloped for five years or more following their initial booking, and we currently have plans to use anticipated capital resources to develop the proved undeveloped reserves remaining as of December 31, 2019 within five years of booking these reserves.

The following table summarizes changes in our estimated proved undeveloped reserves at December 31, 2019.

	Proved Undeveloped Reserves (MBOE)(1)
As of December 31, 2018	121,052
Extensions and discoveries	44,410
Net divestitures of minerals-in-place	(1,571)
Revisions of prior estimates	6,559
Conversion of proved undeveloped to proved developed	(23,629)
As of December 31, 2019	146,821

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth, since 2016, proved undeveloped reserves converted to proved developed reserves during each year and the investments associated with these conversions (dollars in thousands).

	Proved Undeveloped Reserve Converted to Proved Developed Reserves			Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves
	Oil (MBbl)	Natural Gas (Bcf)	Total (MBOE)(1)	
2016	4,705	13.1	6,883	$ 94,579
2017	9,300	45.0	16,808	211,860
2018	16,009	61.7	26,283	356,830
2019	13,832	58.8	23,629	318,609
Total	43,846	178.6	73,603	$981,878

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth additional summary information by operating area with respect to our estimated net proved reserves at December 31, 2019.

	Net Proved Reserves[1]				
	Oil (MBbl)	Natural Gas (Bcf)	Oil Equivalent (MBOE)[4]	Standardized Measure[2] (in millions)	PV-10[3] (in millions)
Southeast New Mexico/West Texas:					
Delaware Basin	139,595	559.2	232,793	$1,877.1	$2,074.8
South Texas:					
Eagle Ford[5]	8,350	17.2	11,219	123.6	136.6
Northwest Louisiana					
Haynesville	—	45.9	7,652	31.0	34.3
Cotton Valley[6]	46	4.9	867	2.3	2.5
Area Total	46	50.8	8,519	33.3	36.8
Total	147,991	627.2	252,531	$2,034.0	$2,248.2

(1) Numbers in table may not total due to rounding.

(2) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

(3) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2019 may be reconciled to our Standardized Measure of discounted future net cash flows at such date by adding the discounted future income taxes associated with such reserves to the Standardized Measure. The discounted future income taxes at December 31, 2019 were approximately $214.2 million.

(4) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) Includes one well producing oil from the Austin Chalk formation in La Salle County, Texas and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(6) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

Technology Used to Establish Reserves

Under current SEC rules, proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, we used technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and technical data used in the estimation of our proved reserves include, but are not limited to, electric logs, radioactivity logs, core analyses, geologic maps and available pressure and production data, seismic data and well test data. Reserves for proved developed producing wells were estimated using production performance and material balance methods. Certain new producing properties with little production history were forecasted using a combination of production performance and analogy to offset production. Non-producing reserves estimates for both developed and undeveloped properties were forecasted using either volumetric and/or analogy methods.

Internal Control Over Reserves Estimation Process

We maintain an internal staff of petroleum engineers and geoscience professionals to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. Our Executive Vice President of Reservoir Engineering and Chief Technology Officer is primarily responsible for overseeing the preparation of our reserves estimates. He received his Bachelor and Master of Science degrees in Petroleum Engineering from Texas A&M University, is a Licensed Professional Engineer in the State of Texas and has over 42 years of industry experience. Following the preparation of our reserves estimates, these estimates are audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. The Operations and Engineering Committee of our Board of Directors reviews the reserves report and our reserves estimation process, and the results of the reserves report and the independent audit of our reserves are reviewed by other members of our Board of Directors as well.

ACREAGE SUMMARY

The following table sets forth the approximate acreage in which we held a leasehold, mineral or other interest at December 31, 2019.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/West Texas:						
Delaware Basin	145,800	75,000	85,500	53,200	231,300	128,200
South Texas:						
Eagle Ford	29,200	26,500	2,000	1,900	31,200	28,400
Northwest Louisiana (1):						
Haynesville	17,500	10,000	—	—	17,500	10,000
Cotton Valley	16,100	14,900	—	—	16,100	14,900
Area Total (2)	19,700	18,300	—	—	19,700	18,300
Total	194,700	119,800	87,500	55,100	282,200	174,900

(1) Developed acres include 2,800 gross and net mineral acres in Northwest Louisiana.

(2) Some of the same leases cover the gross and net acreage shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the gross and net acreage for both formations is not equal to the total gross and net acreage for Northwest Louisiana.

UNDEVELOPED ACREAGE EXPIRATION

The following table sets forth the approximate number of gross and net undeveloped acres at December 31, 2019 that will expire over the next five years by operating area unless production is established within the spacing units covering the acreage prior to the expiration dates, the existing leases are renewed prior to expiration or continued operations maintain the leases beyond the expiration of each respective primary term. Undeveloped acreage expiring in 2025 and beyond totals 12,700 net acres, of which 9,900 net acres do not expire until 2028 and beyond. All of our leasehold in the Haynesville and Cotton Valley plays in Northwest Louisiana was held by existing production at December 31, 2019.

	Acres Expiring 2020		Acres Expiring 2021		Acres Expiring 2022		Acres Expiring 2023		Acres Expiring 2024	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/ West Texas:										
Delaware Basin (1)	17,000	10,700	26,400	14,800	18,600	9,900	4,800	4,800	300	300
South Texas:										
Eagle Ford	1,600	1,800	400	100	—	—	—	—	—	—
Total	18,600	12,500	26,800	14,900	18,600	9,900	4,800	4,800	300	300

(1) Approximately 47% of the acreage expiring in the Delaware Basin in the next five years is associated with our Twin Lakes asset area in northern Lea County, New Mexico. We expect to hold or extend portions of certain expiring acreage in the Delaware Basin through our 2020 drilling activities or by paying an additional lease bonus, where applicable.

Many of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless operations are conducted to maintain the respective leases in effect beyond the expiration of the primary term or production from the acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production in commercial quantities in most cases. We also have options to extend some of our leases through additional lease bonus payments prior to the expiration of the primary term of the leases. In addition, we may attempt to secure a new lease upon the expiration of certain of our acreage; however, there may be third-party leases, or top leases, that become effective immediately if our leases expire at the end of their respective terms and production has not been established prior to such date or operations are not conducted to maintain the leases in effect beyond the primary term. As of December 31, 2019, our leases are primarily fee and state leases with primary terms of three to five years and federal leases with primary terms of 10 years. We believe that our lease terms are similar to our competitors' lease terms as they relate to both primary term and royalty interests.

DRILLING RESULTS

The following table summarizes our drilling activity for the years ended December 31, 2019, 2018 and 2017.

	Year Ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	147	62.0	118	54.7	72	43.7
Dry	—	—	—	—	—	—
Exploration Wells						
Productive	25	13.3	35	20.8	33	22.3
Dry	—	—	—	—	—	—
Total Wells						
Productive	172	75.3	153	75.5	105	66.0
Dry	—	—	—	—	—	—

MARKETING AND CUSTOMERS

Our crude oil is sold under both long-term and short-term oil purchase agreements with unaffiliated purchasers based on published price bulletins reflecting an established field posting price. As a consequence, the prices we receive for crude oil and our heavier liquid products move up and down in direct correlation with the oil market as it reacts to supply and demand factors. The prices of our lighter liquid products move up and down independently of any relationship between the crude oil and natural gas markets. Transportation costs related to moving crude oil and liquids are also deducted from the price received for crude oil and liquids.

Our natural gas is sold under both long-term and short-term natural gas purchase agreements. Natural gas produced by us is sold at various delivery points to both unaffiliated independent marketing companies and unaffiliated midstream companies. The prices we receive are calculated based on various pipeline indices. When there is an opportunity to do so, we may have our natural gas processed at San Mateo’s or third parties’ processing facilities to extract liquid hydrocarbons from the natural gas. We are then paid for the extracted liquids based on either a negotiated percentage of the proceeds that are generated from the sale of the liquids, or other negotiated pricing arrangements using then-current market pricing less fixed rate processing, transportation and fractionation fees.

The prices we receive for our oil and natural gas production fluctuate widely. Factors that, directly or indirectly, cause price fluctuations include the level of demand for oil and natural gas, the actions of the Organization of Petroleum Exporting Countries (“OPEC”), weather conditions, including hurricanes in the Gulf Coast region, oil and natural gas storage levels, transportation capacity constraints, domestic and foreign governmental regulations, price and availability of alternative fuels, political conditions in oil and natural gas producing regions, the domestic and foreign supply of oil and natural gas, the price of foreign imports and overall economic conditions. Decreases in these commodity prices adversely affect the carrying value of our proved reserves and our revenues, profitability and cash flows. Short-term disruptions of our oil and natural gas production occur from time to time due to downstream pipeline system failure, capacity issues and scheduled maintenance, as well as maintenance and repairs involving our own well operations. These situations, if they occur, curtail our production capabilities and ability to maintain a steady source of revenue. See “Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil and Natural Gas Prices and the Continued Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations.”

The prices we receive for our oil and natural gas production often reflect a discount to the relevant benchmark prices, such as the NYMEX West Texas Intermediate oil price or the NYMEX Henry Hub natural gas price. The difference between the benchmark price and the price we receive is called a differential. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could adversely affect our business, financial condition, results of operations and cash flows. See "Risk Factors — An Increase in the Differential between the NYMEX or Other Benchmark Prices of Oil and Natural Gas and the Wellhead Price We Receive for Our Production Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows."

For the years ended December 31, 2019, 2018 and 2017, we had two, four and four significant purchasers that accounted for approximately 67%, 60% and 60%, respectively, of our total oil, natural gas and NGL revenues. If we lost one or more of these significant purchasers and were unable to sell our production to other purchasers on terms we consider acceptable, it could materially and adversely affect our business, financial condition, results of operations and cash flows. For further details regarding these purchasers, see Note 2 to the consolidated financial statements in this Annual Report. Such information is incorporated herein by reference.

TITLE TO PROPERTIES

We endeavor to ensure that title to our properties is in accordance with standards generally accepted in the oil and natural gas industry. While we rely upon the judgment of oil and natural gas lease brokers and/or landmen in ascertaining title for certain leasehold acquisitions, we typically obtain detailed title opinions prior to drilling an oil and natural gas well. Some of our acreage is subject to agreements that require the drilling of wells or the undertaking of other exploratory or development activities in order to retain our interests in the acreage. Our title to these contractual interests may be contingent upon our satisfactory fulfillment of such obligations. Some of our properties are also subject to customary royalty interests, liens incident to financing arrangements, operating agreements, taxes and other similar burdens that we believe will not materially interfere with the use and operation of these properties or affect the value thereof. Generally, we intend to conduct operations, make lease rental payments or produce oil and natural gas from wells in paying quantities, where required, prior to expiration of various time periods in order to avoid lease termination. See "Risk Factors — We May Incur Losses or Costs as a Result of Title Deficiencies in the Properties in Which We Invest."

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to customary encumbrances, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens or encumbrances will materially interfere with the use and operation of these properties in the conduct of our business. In addition, we believe that we have obtained sufficient right-of-way grants and permits from public authorities and private parties for us to operate our business.

SEASONALITY

Generally, but not always, the demand and price levels for natural gas increase during winter and decrease during summer. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can place increased demand on storage volumes. Demand for oil and heating oil is also generally higher in the winter and the summer driving season, although oil prices are affected more significantly by global supply and demand. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations. Certain of our drilling, completion and other operations are also subject to seasonal limitations where equipment may not be available during periods of peak demand or where weather conditions and events result in delayed operations. See "Risk Factors — Because Our Reserves and Production Are Concentrated in a Few Core Areas, Problems in Production and Markets Relating to a Particular Area Could Have a Material Impact on Our Business."

COMPETITION

The oil and natural gas industry is highly competitive. We compete with major and independent oil and natural gas companies for exploration opportunities and acreage acquisitions as well as drilling rigs and other equipment and labor required to drill, complete, operate and develop our properties. We also compete with public and private midstream companies for natural gas gathering and processing opportunities, as well as salt water gathering and disposal and oil gathering and transportation activities in the areas in which we operate. In addition, competition in the midstream industry is based on the geographic location of facilities, business reputation, reliability and pricing arrangements for the services offered. San Mateo competes with other midstream companies that provide similar services in its areas of operations, and such companies may have legacy relationships with producers in those areas and may have a longer history of efficiency and reliability.

Many of our competitors have substantially greater financial resources, staffs, facilities and other resources. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which could adversely affect our competitive position. These competitors may be willing and able to pay more for drilling rigs, leasehold and mineral acreage, productive oil and natural gas properties or midstream facilities and may be able to identify, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our competitors may also be able to afford to purchase and operate their own drilling rigs and hydraulic fracturing equipment.

Our ability to drill and explore for oil and natural gas, to acquire properties and to provide competitive midstream services will depend upon our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors may have a longer history of operations.

The oil and natural gas industry also competes with other energy-related industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. See “Risk Factors — Competition in the Oil and Natural Gas Industry Is Intense, Making It More Difficult for Us to Acquire Properties, Market Oil and Natural Gas, Provide Midstream Services and Secure Trained Personnel.”

REGULATION

Oil and Natural Gas Regulation

Our oil and natural gas exploration, development, production, midstream and related operations are subject to extensive federal, state and local laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial monetary penalties or delay or suspension of operations. The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these laws, rules and regulations are frequently amended or reinterpreted and new laws, rules and regulations are promulgated, we are unable to predict the future cost or impact of complying with the laws, rules and regulations to which we are, or will become, subject. Our competitors in the oil and natural gas industry are generally subject to the same regulatory requirements and restrictions that affect our operations.

Texas, New Mexico, Louisiana and many other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration, development and production of oil and natural gas. Many states also have laws, rules and regulations addressing conservation of oil and natural gas and other matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, the regulation of well spacing, the surface use and restoration of properties upon which wells are drilled, the prohibition, restriction or limitation of venting or flaring natural gas, the sourcing and disposal of water used and produced in the drilling and completion process and the plugging and abandonment of wells. While not presently the case in the states in which we operate, some states restrict production to the market demand for oil and natural gas or prescribe ceiling prices for natural gas sold within their boundaries. Additionally, some regulatory agencies have, from time to time, imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below natural production capacity in order to conserve supplies of oil and natural gas. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Some of our oil and natural gas leases are issued by agencies of the federal government, as well as agencies of the states in which we operate. These leases contain various restrictions on access and development and other requirements that may impede our ability to conduct operations on the acreage represented by these leases. See "Risk Factors — Approximately 26% of Our Leasehold and Mineral Acres in the Delaware Basin Are Located on Federal Lands, Which Are Subject to Administrative Permitting Requirements and Potential Federal Legislation, Regulation and Orders That May Limit or Restrict Oil and Natural Gas Operations on Federal Lands."

Our sales of natural gas, as well as the revenues we receive from our sales, are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 (the "NGA"), as well as under Section 311 of the Natural Gas Policy Act of 1978 (the "NGPA"). Natural gas gathering facilities are exempt from the jurisdiction of FERC under section 1(b) of the NGA, and intrastate crude oil pipeline facilities are not subject to FERC's jurisdiction under the Interstate Commerce Act (the "ICA"). State regulation of natural gas gathering facilities and intrastate crude oil pipeline facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements or complaint-based rate regulation. We believed, as of February 25, 2020, that the natural gas pipelines in our gathering systems met the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. In December 2018, San Mateo placed into service the Rustler Breaks Oil Pipeline System following an open season to gauge shipper interest in committed crude oil interstate transportation service on the Rustler Breaks Oil Pipeline System earlier in 2018. The Rustler Breaks Oil Pipeline System, which is subject to FERC jurisdiction, includes approximately 17 miles of 10-inch diameter crude oil gathering and transportation pipelines from origin points in Eddy County, New Mexico to an interconnect with Plains Pipeline, L.P. We believed, as of February 25, 2020, that the other crude oil pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as an intrastate facility not subject to FERC jurisdiction.

In 2005, Congress enacted the Energy Policy Act of 2005 (the "Energy Policy Act"). The Energy Policy Act, among other things, amended the NGA to prohibit market manipulation in connection with the purchase or sale of natural gas or the purchase or sale of natural gas transportation services subject to FERC jurisdiction by any entity and to direct FERC to facilitate transparency in the market for the sale or transportation of natural gas in interstate commerce. The Energy Policy Act also significantly increased the penalties for violations of, among other things, the NGA, the NGPA or FERC rules, regulations or orders thereunder. FERC has promulgated regulations to implement the Energy Policy Act. Should we violate the anti-market manipulation laws and related regulations, in addition to FERC-imposed penalties and disgorgement, we may also be subject to third-party damage claims.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies (and to a limited extent by FERC, as noted above). The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Because these regulations will apply to all intrastate natural gas shippers within the same state on a comparable basis, we believe that regulation in any states in which we operate will not affect our operations in any way that is materially different from our competitors that are similarly situated.

As mentioned above, in December 2018, San Mateo placed into service the Rustler Breaks Oil Pipeline System. The Rustler Breaks Oil Pipeline System is subject to regulation by FERC under the ICA and the Energy Policy Act of 1992 (the “EP Act”). The ICA and its implementing regulations give FERC authority to regulate the rates charged for service on interstate common carrier pipelines and generally require the rates and practices of interstate crude oil pipelines to be just, reasonable, not unduly discriminatory and not unduly preferential. The ICA also requires tariffs that set forth the rates an interstate crude oil pipeline company charges for providing transportation services on its FERC-jurisdictional pipelines, as well as the rules and regulations governing these services, to be maintained on file with FERC and posted publicly. The EP Act and its implementing regulations also generally allow interstate crude oil pipelines to annually index their rates up to a prescribed ceiling level and require that such pipelines index their rates down to the prescribed ceiling level if the index is negative.

The price we receive from the sale of oil and NGLs will be affected by the availability, terms and cost of transportation of such products to market. As noted above, under rules adopted by FERC, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. Intrastate oil pipeline transportation rates are subject to regulations promulgated by state regulatory commissions, which vary from state to state. We are not able to predict with certainty the effects, if any, of these regulations on our operations.

In 2007, the Energy Independence & Security Act of 2007 (the “EISA”) went into effect. The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations and establishes penalties for violations thereunder.

The Pipeline and Hazardous Materials Safety Administration (“PHMSA”) imposes pipeline safety requirements on regulated pipelines and gathering lines pursuant to its authority under the Natural Gas Pipeline Safety Act and the Hazardous Liquid Pipeline Safety Act, each as amended. The Rustler Breaks Oil Pipeline System is subject to PHMSA oversight. The Department of Transportation, through PHMSA, has established rules regarding integrity management programs for interstate oil pipelines, including the Rustler Breaks Oil Pipeline System. In recent years, pursuant to these laws and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, PHMSA has expanded its regulation of gathering lines, subjecting previously unregulated pipelines to requirements regarding damage prevention, corrosion control, public education programs, maximum allowable operating pressure limits and other requirements. Certain of our natural gas gathering lines are federally “regulated gathering lines” subject to PHMSA requirements. On April 8, 2016, PHMSA published a notice of proposed rulemaking that would amend existing integrity management requirements, expand assessment and repair requirements in areas with medium population densities and extend regulatory requirements to onshore natural gas gathering lines that are currently exempt. On January 13, 2017, PHMSA issued, but did not publish, a similar proposed rule for hazardous liquids (i.e., oil) pipelines and gathering lines. It is unclear when or if this rule will go into effect as, on January 20, 2017, the Trump administration requested that all regulations that had been sent to the Office of the Federal Register, but not yet published, be immediately withdrawn for further review. In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. See “Risk Factors — We May Incur Significant Costs and Liabilities Resulting from Compliance with Pipeline Safety Regulations.”

Additional expansion of pipeline safety requirements or our operations could subject us to more stringent or costly safety standards, which could result in increased operating costs or operational delays.

U.S. Federal and State Taxation

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and additional increases may occur. In January 2019, a bill was introduced in the New Mexico Senate to add a surtax on natural gas processors that would start at $0.60 per MMBtu in 2020 and escalate to $3.00 per MMBtu by 2024. If passed, such a surtax would adversely affect the ability of San Mateo and other natural gas processors to operate in New Mexico and would adversely affect the prices we receive for our natural gas processed in New Mexico. In addition, from time to time there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals, including proposals that would eliminate allowing small U.S. oil and natural gas companies to deduct intangible drilling costs as incurred and percentage depletion. Changes to tax laws could adversely affect our business and our financial results. See "Risk Factors — We Are Subject to Federal, State and Local Taxes, and May Become Subject to New Taxes or Have Eliminated or Reduced Certain Federal Income Tax Deductions Currently Available with Respect to Oil and Natural Gas Exploration and Production Activities as a Result of Future Legislation, Which Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows" and "Risk Factors — The Tax Cuts and Jobs Act May Impact Our Ability to Fully Utilize Our Interest Expense Deductions and Net Operating Loss Carryovers to Fully Offset Our Taxable Income in Future Periods."

Hydraulic Fracturing Policies and Procedures

We use hydraulic fracturing as a means to maximize the recovery of oil and natural gas in almost every well that we drill and complete. Our engineers responsible for these operations attend specialized hydraulic fracturing training programs taught by industry professionals. Although average drilling and completion costs for each area will vary, as will the cost of each well within a given area, on average approximately one-half to two-thirds of the total well costs for our horizontal wells are attributable to overall completion activities, which are primarily focused on hydraulic fracture treatment operations. These costs are treated in the same way as all other costs of drilling and completion of our wells and are included in and funded through our normal capital expenditure budget. A change to any federal and state laws and regulations governing hydraulic fracturing could impact these costs and adversely affect our business and financial results. See "Risk Factors — Federal and State Legislation and Regulatory Initiatives Relating to Hydraulic Fracturing Could Result in Increased Costs and Additional Operating Restrictions or Delays."

The protection of groundwater quality is important to us. We believe that we follow all state and federal regulations and apply industry standard practices for groundwater protection in our operations. These measures are subject to close supervision by state and federal regulators (including the BLM, with respect to federal acreage).

Although rare, if the cement and steel casing used in well construction requires remediation, we deal with these problems by evaluating the issue and running diagnostic tools, including cement bond logs and temperature logs, and conducting pressure testing, followed by pumping remedial cement jobs and taking other appropriate remedial measures.

The vast majority of our hydraulic fracturing treatments are made up of water and sand or other kinds of man-made proppants. We use major hydraulic fracturing service companies that track and report chemical additives that are used in fracturing operations as required by the appropriate governmental agencies. These service companies fracture stimulate thousands of wells each year for the industry and invest millions of dollars to protect the environment through rigorous safety procedures and also work to develop more environmentally friendly fracturing fluids. We follow safety procedures and monitor all aspects of our fracturing operations in an attempt to ensure environmental protection. We do not pump any diesel in the fluid systems of any of our fracture stimulation procedures.

While current fracture stimulation procedures utilize a significant amount of water, we typically recover less than 10% of this fracture stimulation water before produced salt water becomes a significant portion of the fluids produced. All produced water, including fracture stimulation water, is either recycled or disposed of in permitted and regulated disposal facilities in a way that is designed to avoid any impact to surface waters. Since mid-2015, we have been recycling a portion of our produced salt water in certain of our Delaware Basin asset areas. Recycling produced salt water mitigates the need for salt water disposal and also provides cost savings to us.

Environmental, Health and Safety Regulation

The exploration, development, production, gathering and processing of oil and natural gas, including the operation of salt water injection and disposal wells, are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, drilling, completing and operating oil and natural gas wells, midstream facilities and salt water injection and disposal wells. Our activities are subject to a variety of environmental laws and regulations, including but not limited to: the Oil Pollution Act of 1990 (the "OPA 90"), the Clean Water Act (the "CWA"), the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), the Resource Conservation and Recovery Act ("RCRA"), the Clean Air Act (the "CAA"), the Safe Drinking Water Act (the "SDWA") and the Occupational Safety and Health Act ("OSHA"), as well as comparable state statutes and regulations. We are also subject to regulations governing the handling, transportation, storage and disposal of wastes generated by our activities and naturally occurring radioactive materials ("NORM") that may result from our oil and natural gas operations. Administrative, civil and criminal fines and penalties may be imposed for noncompliance with these environmental laws and regulations, and violations and liability with respect to these laws and regulations could also result in remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking some activities, may require notice to stakeholders of proposed and ongoing operations, limit or prohibit other activities because of protected wetlands, areas or species and require investigation and cleanup of pollution. These laws, rules and regulations may also restrict the production rate of oil and natural gas below the rate that would otherwise be possible. We expect to remain in compliance in all material respects with currently applicable environmental laws and regulations and do not expect that these laws and regulations will have a material adverse impact on us.

The OPA 90 and its regulations impose requirements on "responsible parties" related to the prevention of crude oil spills and liability for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" under the OPA 90 may include the owner or operator of an onshore facility. The OPA 90 subjects responsible parties to strict, joint and several financial liability for removal and remediation costs and other damages, including natural resource damages, caused by an oil spill that is covered by the statute. Failure to comply with the OPA 90 may subject a responsible party to civil or criminal enforcement action.

The CWA and comparable state laws impose restrictions and strict controls regarding the discharge of produced waters, fill materials and other materials into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Permits are required to discharge pollutants into certain state and federal waters and to conduct construction activities in those waters and wetlands. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other pollutants and impose liability for the costs of removal or remediation of contamination resulting from such discharges. In September 2015, a rule issued by the Environmental Protection Agency (the "EPA") and U.S. Army Corps of Engineers (the "Corps") to revise the definition of "waters of the United States" ("WOTUS") for all CWA programs, thereby defining the scope of the EPA's and the Corps' jurisdiction, became effective. To the extent the revision expands the scope of jurisdiction of the CWA, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

However, in June 2017, the EPA and the Corps proposed a rule that would initiate the first step in a two-step process intended to review and revise the definition of WOTUS. Under the proposal, the first step would be to rescind the May 2015 final rule and put back into effect the narrower language defining WOTUS under the CWA that existed prior to the rule. The second step would be a notice-and-comment rule-making in which the agencies would conduct a substantive reevaluation of the definition of WOTUS. In September 2019, the EPA finalized the first step in this process.

CERCLA, also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on various 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 site where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Persons who are responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances and for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. Although CERCLA generally exempts petroleum from the definition of hazardous substances, our operations may, and in all likelihood will, involve the use or handling of materials that are classified as hazardous substances under CERCLA. Each state also has environmental cleanup laws analogous to CERCLA.

RCRA and comparable state and local statutes govern the management, including treatment, storage and disposal, of both hazardous and nonhazardous solid wastes. We generate hazardous and nonhazardous solid waste in connection with our routine operations. RCRA includes a statutory exemption that allows many wastes associated with crude oil and natural gas exploration and production to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. Not all of the wastes we generate fall within these exemptions. At various times in the past, proposals have been made to amend RCRA to eliminate the exemption applicable to crude oil and natural gas exploration and production wastes. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses. Hazardous wastes are subject to more stringent and costly disposal requirements than nonhazardous wastes.

The CAA, as amended, restricts the emission of air pollutants from many sources, including oil and natural gas production. In addition, certain states have comparable legislation, which may be more restrictive than the CAA. These laws and any implementing regulations impose stringent air permit requirements and require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, or to use specific equipment or technologies to control emissions. See "Risk Factors — New Regulations on All Emissions from Our Operations Could Cause Us to Incur Significant Costs." In January 2019, New Mexico's governor signed an executive order declaring that New Mexico would support the goals of the Paris Agreement by joining the U.S. Climate Alliance, a bipartisan coalition of governors committed to reducing greenhouse gas emissions consistent with the goals of the Paris Agreement. The stated objective of the executive order is to achieve a statewide reduction in greenhouse gas emissions of at least 45% by 2030 as compared to 2005 levels. The executive order also requires New Mexico regulatory agencies to create an "enforceable regulatory framework" to ensure methane emission reductions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal, cleanup or operating requirements could materially adversely affect our operations and financial condition, as well as those of the oil and natural gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," and including carbon dioxide and methane, may be contributing to the warming of the Earth's atmosphere. Based on these findings, the EPA has begun adopting and implementing a comprehensive suite of regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. Legislative and regulatory initiatives related to climate change and greenhouse gas emissions could, and in all likelihood would, require us to incur increased operating costs adversely affecting our profits and could adversely affect demand for the oil and natural gas we produce, depressing the prices we receive for oil and natural gas. See "Risk Factors — Legislation or Regulations Restricting Emissions of Greenhouse Gases Could Result in Increased Operating Costs and Reduced Demand for the Oil, Natural Gas and NGLs We Produce, while the Physical Effects of Climate Change Could Disrupt Our Production and Cause Us to Incur Significant Costs in Preparing for or Responding to Those Effects" and "Risk Factors — New Regulations on All Emissions from Our Operations Could Cause Us to Incur Significant Costs."

We own and operate underground injection wells throughout our areas of operation. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. Underground injection allows us to safely and economically dispose of produced water. The SDWA establishes a regulatory framework for underground injection, the primary objective of which is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. The disposal of hazardous waste by underground injection is subject to stricter requirements than the disposal of produced water. Failure to obtain, or abide by the requirements for the issuance of, necessary permits could subject us to civil and/or criminal enforcement actions and penalties. In addition, in some instances, the operation of underground injection wells has been alleged to cause earthquakes (induced seismicity) as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. In addition, a number of lawsuits have been filed in some states alleging that fluid injection or oil and natural gas extraction have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise, to assess the relationship between seismicity and the use of such wells. For example, in October 2014, the Texas Railroad Commission (the "TRC"), adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water or other oil and natural gas waste to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. If the permittee or an applicant for a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be, or determined to be, contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that disposal well. The TRC has used this authority to deny permits for waste disposal wells. The potential adoption of federal, state and local legislation and regulations intended to address induced seismicity in the areas in which we operate could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could result in increased costs and additional operating restrictions or delays.

Our activities involve the use of hydraulic fracturing. For more information on our hydraulic fracturing operations, see "—Hydraulic Fracturing Policies and Procedures." Hydraulic fracturing is generally exempted from federal regulation as underground injection (unless diesel is a component of the fracturing fluid) under the SDWA. The process of hydraulic fracturing is typically regulated by state oil and natural gas commissions. Various policy makers, regulatory agencies and political candidates at the federal, state and local levels have proposed restrictions on hydraulic fracturing, including its outright prohibition. For example, certain candidates seeking the office of the President of the United States in 2020 have pledged to ban hydraulic fracturing. It is possible that any such restrictions on hydraulic fracturing may particularly target activity on federal lands, which could adversely impact our operations in the Delaware Basin. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce. Some states and localities have placed additional regulatory burdens upon hydraulic fracturing activities and, in some areas, severely restricted or prohibited those activities. In 2019 and 2020, separate bills were introduced in the New Mexico Senate to place a moratorium on hydraulic fracturing. In addition, separate and apart from the referenced potential connection between injection wells and seismicity, concerns have been raised that hydraulic fracturing activities may be correlated to induced seismicity. The scientific community and regulatory agencies at all levels are studying the possible linkage between oil and natural gas activity and induced seismicity, and some state regulatory agencies have modified their regulations or guidance to mitigate potential causes of induced seismicity. If the exemption for hydraulic fracturing is removed from the SDWA, or if other legislation is enacted at the federal, state or local level imposing any restrictions on the use of hydraulic fracturing, this could have a significant impact on our financial condition, results of operations and cash flows. Additional burdens upon hydraulic fracturing, such as reporting or permitting requirements, would result in additional expense and delay in our operations. See “Risk Factors — Federal and State Legislation and Regulatory Initiatives Relating to Hydraulic Fracturing Could Result in Increased Costs and Additional Operating Restrictions or Delays” and “Risk Factors — Approximately 26% of Our Leasehold and Mineral Acres in the Delaware Basin Are Located on Federal Lands, Which Are Subject to Administrative Permitting Requirements and Potential Federal Legislation, Regulation and Orders That May Limit or Restrict Oil and Natural Gas Operations on Federal Lands.”

Oil and natural gas exploration and production operations and other activities have been conducted on some of our properties by previous owners and operators. Materials from these operations remain on some of the properties, and, in some instances, require remediation. In addition, we occasionally must agree to indemnify sellers of producing properties against some of the liability for environmental claims associated with the properties we purchase. While we do not believe that costs we incur for compliance with environmental regulations and remediating previously or currently owned or operated properties will be material, we cannot provide any assurances that these costs will not result in material expenditures that adversely affect our profitability.

Additionally, in the course of our routine oil and natural gas operations, surface spills and leaks, including casing leaks, of oil, produced water or other materials may occur, and we may incur costs for waste handling and environmental compliance. It is also possible that our oil and natural gas operations may require us to manage NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contact with crude oil and natural gas production and processing streams. Some states, including Texas, New Mexico and Louisiana, have enacted regulations governing the handling, treatment, storage and disposal of NORM. Moreover, we will be able to control directly the operations of only those wells we operate. Despite our lack of control over wells owned partly by us but operated by others, the failure of the operator to comply with the applicable environmental regulations may, in certain circumstances, be attributable to us.

We are subject to the requirements of OSHA and comparable state statutes. The OSHA Hazard Communication Standard, the “community right-to-know” regulations under Title III of the federal Superfund Amendments and Reauthorization Act and similar state statutes require us to organize information about hazardous materials used, released or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in OSHA workplace standards.

We are subject to laws and regulations governing the security of hazardous materials under the Federal Homeland Security Act of 2002, as administered by the Department of Homeland Security (the "DHS"). The DHS promulgated the Chemical Facility Anti-Terrorism Standards to identify and secure chemical facilities that present the greatest security risk using a risk-based tiering structure. Due to the composition of the product it processes, the Black River Processing Plant was required to register with the DHS. We have submitted the required "Top-Screen" survey to the DHS and are awaiting its review by the DHS. We expect to continue to incur costs associated with administrative controls and enhanced physical security measures for the Black River Processing Plant if it is designated as a tiered facility by the DHS.

The Endangered Species Act (the "ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in material restrictions on land use and may materially impact oil and natural gas development. Our oil and natural gas operations in certain of our operating areas could also be adversely affected by seasonal or permanent restrictions on drilling activity designed to protect certain wildlife in the Delaware Basin and other areas in which we operate. See "Risk Factors — We Are Subject to Government Regulation and Liability, Including Complex Environmental Laws, Which Could Require Significant Expenditures." Our ability to maximize production from our leases may be adversely impacted by these restrictions.

Approximately 26% of our Delaware Basin acreage position, including all of the BLM Acquisition, consists of federal leasehold administered by the BLM. Permitting for oil and natural gas activities on federal lands can take significantly longer than the permitting process for oil and natural gas activities not located on federal lands. Delays in obtaining necessary permits can disrupt our operations and have an adverse effect on our business. These BLM leases contain relatively standardized terms and require compliance with detailed regulations and orders, which are subject to change. These operations are also subject to BLM rules regarding engineering and construction specifications for production facilities, safety procedures, the valuation of production, the payment of royalties, the removal of facilities, the posting of bonds, hydraulic fracturing, the control of air emissions and other areas of environmental protection. These rules could result in increased compliance costs for our operations, which in turn could have an adverse effect on our business and results of operations. Under certain circumstances, the BLM may require our operations on federal leases to be suspended or terminated. Oil and natural gas exploration and production activities on federal lands are also subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. This process has the potential to delay or even halt development of future oil and natural gas projects with NEPA applicability.

We have not in the past been, and do not anticipate in the near future to be, required to expend amounts that are material in relation to our total capital expenditures as a result of environmental laws and regulations, but since these laws and regulations are periodically amended, we are unable to predict the ultimate cost of compliance. We have no assurance that more stringent laws and regulations protecting the environment will not be adopted or that we will not otherwise incur material expenses in connection with environmental laws and regulations in the future. See "Risk Factors — We Are Subject to Government Regulation and Liability, Including Complex Environmental Laws, Which Could Require Significant Expenditures."

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly permitting, emissions control, waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial condition. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we have no assurance that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons.

We maintain insurance against some, but not all, potential risks and losses associated with our industry and operations. We generally do not carry business interruption insurance. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could materially adversely affect our financial condition, results of operations and cash flows. See "Risk Factors — Insurance Against All Operational Risks is Not Available to Us."

OFFICE LEASE

Our corporate headquarters are located at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. See Note 4 to the consolidated financial statements in this Annual Report for more details regarding our office lease. Such information is incorporated herein by reference.

EMPLOYEES

At December 31, 2019, we had 304 full-time employees. We believe that our relationships with our employees are satisfactory. No employee is covered by a collective bargaining agreement. From time to time, we use the services of independent consultants and contractors to perform various professional services, including in the areas of geology and geophysics, land, production and midstream operations, construction, design, well site surveillance and supervision, permitting and environmental assessment, legal and income tax preparation and accounting services. Independent contractors, at our request, drill all of our wells and usually perform field and on-site production operation services for us, including midstream services, facilities construction, pumping, maintenance, dispatching, inspection and testing. If significant opportunities for company growth arise and require additional management and professional expertise, we will seek to employ qualified individuals to fill positions where that expertise is necessary to develop those opportunities.

AVAILABLE INFORMATION

Our Internet website address is *www.matadorresources.com*. We make available, free of charge, through our website, our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, the charters of our Audit Committee, Corporate Governance Committee, Executive Committee, Nominating Committee and Strategic Planning and Compensation Committee, our Code of Ethics and Business Conduct for Officers, Directors and Employees and information regarding certain of our ESG initiatives are available through our website, and we also intend to disclose any amendments to our Code of Ethics and Business Conduct, or waivers to such code on behalf of our Chief Executive Officer, Chief Financial Officer or Chief Accounting Officer, on our website. All of these corporate governance materials are available free of charge and in print to any shareholder who provides a written request to the Corporate Secretary at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. The contents of our website are not intended to be incorporated by reference into this Annual Report or any other report or document we file and any reference to our website is intended to be an inactive textual reference only.

ITEM 1A. RISK FACTORS.

RISKS RELATED TO THE OIL AND NATURAL GAS INDUSTRY AND OUR BUSINESS

Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil and Natural Gas Prices and the Continued Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations.

The prices we receive for the oil and natural gas we produce heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital, borrowing capacity under our Credit Agreement and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile and will likely continue to be volatile in the future. During 2019, the average price of oil was $57.01 per Bbl, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date, and the average price of natural gas was $2.53 per MMBtu, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. During 2019, oil prices began the year at $45.41 per Bbl, which was the low oil price for 2019, and increased steadily, reaching a high of $66.30 per Bbl in late April. Oil prices declined during the third quarter of 2019 before increasing again during the fourth quarter of 2019 to finish the year at $61.06 per Bbl. In early 2020, oil prices have been particularly volatile, ranging from a high of $65.00 per Bbl in early January to below $45.00 per Bbl in late February. Natural gas prices began 2019 at $2.94 per MMBtu, reached a high of $3.59 per MMBtu in mid-January and declined consistently for several months, reaching a low of $2.07 per MMBtu in early August. Natural gas prices then increased to $2.68 per MMBtu in mid-September before declining again to end 2019 at $2.19 per MMBtu.

Because we use the full-cost method of accounting, we perform a ceiling test quarterly that may be impacted by declining prices of oil and natural gas. Significant price declines have caused us to recognize full-cost ceiling impairments in the past, and should prices decline significantly again, we may recognize further full-cost ceiling impairments. Such full-cost ceiling impairments reduce the book value of our net tangible assets, retained earnings and shareholders' equity but do not impact our cash flows from operations, liquidity or capital resources. See "—We May Be Required to Write Down the Carrying Value of Our Proved Properties under Accounting Rules, and These Write-Downs Could Adversely Affect Our Financial Condition."

The prices we receive for our production, and the levels of our production, depend on numerous factors. These factors include, but are not limited to, the following:

- the domestic and foreign supply of, and demand for, oil and natural gas;
- the actions of OPEC and state-controlled oil companies relating to oil price and production controls;
- the prices and availability of competitors' supplies of oil and natural gas;
- the price and quantity of foreign imports;
- the impact of U.S. dollar exchange rates;
- domestic and foreign governmental regulations and taxes;
- speculative trading of oil and natural gas futures contracts;
- the availability, proximity and capacity of gathering, processing and transportation systems for oil, natural gas and NGLs and gathering and disposal systems for produced water;
- the availability of refining capacity;

- the prices and availability of alternative fuel sources;
- weather conditions and natural disasters;
- political conditions in or affecting oil and natural gas producing regions or countries, including the United States, the Middle East, South America and Russia;
- domestic or global health concerns, including the outbreak of contagious or pandemic diseases, such as the recent coronavirus;
- the continued threat of terrorism and the impact of military action and civil unrest;
- public pressure on, and legislative and regulatory interest within, federal, state and local governments to stop, significantly limit or regulate oil and natural gas operations, including hydraulic fracturing activities;
- the level of global oil and natural gas inventories and exploration and production activity;
- the impact of energy conservation efforts;
- technological advances affecting energy consumption; and
- overall worldwide economic conditions.

These factors make it difficult to predict future commodity price movements with any certainty. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices and are not pursuant to long-term fixed price contracts. Further, oil and natural gas prices do not necessarily fluctuate in direct relation to each other.

Declines in oil or natural gas prices not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically and could reduce the amount we may borrow under our Credit Agreement. Should oil or natural gas prices decrease to economically unattractive levels and remain there for an extended period of time, we may elect to delay some of our exploration and development plans for our prospects, cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities or cease or delay further expansion of our midstream projects, each of which could have a material adverse effect on our business, financial condition, results of operations and reserves. In addition, such declines in commodity prices could cause a reduction in our borrowing base. If the borrowing base were to be less than the outstanding borrowings under our Credit Agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or repay the deficit in equal installments over a period of six months.

Our Exploration, Development, Exploitation and Midstream Projects Require Substantial Capital Expenditures That May Exceed Our Cash Flows from Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth.

Our exploration, development, exploitation and midstream activities are capital intensive. Our cash, operating cash flows, contributions from our joint venture partners and potential future borrowings, under our Credit Agreement, the San Mateo Credit Facility or otherwise, may not be sufficient to fund all of our future acquisitions or future capital expenditures. The rate of our future growth is dependent, at least in part, on our ability to access capital at rates and on terms we determine to be acceptable.

Our cash flows from operations and access to capital are subject to a number of variables, including:

- our estimated proved oil and natural gas reserves;
- the amount of oil and natural gas we produce;
- the prices at which we sell our production;
- the costs of developing and producing our oil and natural gas reserves;
- the costs of constructing, operating and maintaining our midstream facilities;
- our ability to attract third-party customers for our midstream services;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of banks to lend to us; and
- our ability to access the equity and debt capital markets.

In addition, the possible occurrence of future events, such as decreases in the prices of oil and natural gas, or extended periods of such decreased prices, terrorist attacks, wars or combat peace-keeping missions, financial market disruptions, general economic recessions, oil and natural gas industry recessions, large company bankruptcies, accounting scandals, overstated reserves estimates by major public oil companies and disruptions in the financial and capital markets, has caused financial institutions, credit rating agencies and the public to more closely review the financial statements, capital structures and spending and earnings of public companies, including energy companies. Such events have constrained the capital available to the energy industry in the past, and such events or similar events could adversely affect our access to funding for our operations in the future.

If our revenues decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or the value thereof or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, further develop and exploit our current properties or invest in certain opportunities. Alternatively, to fund acquisitions, increase our rate of growth, expand our midstream operations, develop our properties or pay for higher service costs, we may decide to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments, the sale or joint venture of midstream assets, oil and natural gas producing assets or leasehold interests, the sale or joint venture of oil and natural gas mineral interests, the borrowing of funds or otherwise to meet any increase in capital spending. If we succeed in selling additional equity securities or securities convertible into equity securities to raise funds or make acquisitions, the ownership of our existing shareholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing shareholders. If we raise additional capital through the issuance of new debt securities or additional indebtedness, we may become subject to additional covenants that restrict our business activities. If we are unable to raise additional capital from available sources at acceptable terms, our business, financial condition and results of operations could be adversely affected.

Drilling for and Producing Oil and Natural Gas Are Highly Speculative and Involve a High Degree of Operational and Financial Risk, with Many Uncertainties That Could Adversely Affect Our Business.

Exploring for and developing hydrocarbon reserves involves a high degree of operational and financial risk, which precludes us from definitively predicting the costs involved and time required to reach certain objectives. Our drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation and approvals before they can be drilled. The budgeted costs of planning, drilling, completing and operating wells may be exceeded and such costs can increase significantly due to various complications that may arise during drilling, completion and operation. Before a well is spud, we may incur significant geological, geophysical and land costs, including seismic costs, which are incurred whether or not a well eventually produces commercial quantities of hydrocarbons, or is drilled at all. Exploration wells bear a much greater risk of loss than development wells. The analogies we draw from available data from other wells, more fully explored locations or producing fields may not be applicable to our drilling locations. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our operations as proposed and could be forced to modify our drilling plans accordingly.

If we decide to drill a certain location, there is a risk that no commercially productive oil or natural gas reservoirs will be found or produced. We may drill or participate in new wells that are not productive. We may drill or participate in wells that are productive, but that do not produce sufficient net revenues to return a profit after drilling, operating and other costs. There is no way to affirmatively determine in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover exploration, drilling and completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production and reserves from, or abandonment of, the well. The productivity and profitability of a well may be negatively affected by a number of additional factors, including the following:

- general economic and industry conditions, including the prices received for oil and natural gas;
- shortages of, or delays in, obtaining equipment, including hydraulic fracturing equipment, and qualified personnel;
- potential drainage of oil and natural gas from our properties by adjacent operators;
- the existence or magnitude of faults or unanticipated geological features;
- loss of or damage to oilfield development and service tools;
- accidents, equipment failures or mechanical problems;
- title defects of the underlying properties;
- increases in severance taxes;
- adverse weather conditions that delay drilling activities or cause producing wells to be shut in;
- domestic and foreign governmental regulations; and
- proximity to and capacity of gathering, processing and transportation facilities.

Furthermore, our exploration and production operations involve using some of the latest drilling and completion techniques developed by us, other operators and service providers. Risks that we face while drilling and completing horizontal wells include, but are not limited to, the following:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore;
- fracture stimulating the planned number of stages;
- drilling out the plugs between stages following hydraulic fracturing operations; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Each of these risks is magnified in wells with longer laterals, which we expect to drill more of in 2020, including 74% with completed lateral lengths of two miles. If we do not drill productive and profitable wells in the future, our business, financial condition, results of operations, cash flows and reserves could be materially and adversely affected.

Our Operations Are Subject to Operational Hazards and Risks, Which Could Result in Significant Damages and the Loss of Revenue.

There are numerous operational hazards inherent in oil and natural gas exploration, development, production, gathering, transportation and processing, including:

- natural disasters;
- adverse weather conditions;
- domestic or global health concerns, including the outbreak of contagious or pandemic diseases, such as the recent coronavirus;
- loss of drilling fluid circulation;
- blowouts where oil or natural gas flows uncontrolled at a wellhead;
- cratering or collapse of the formation;
- pipe or cement leaks, failures or casing collapses;
- damage to pipelines, processing plants and disposal wells and associated facilities;
- fires or explosions;
- releases of hazardous substances or other waste materials that cause environmental damage;
- pressures or irregularities in formations; and
- equipment failures or accidents.

In addition, there is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations and services, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions to air and water, the underground injection or other disposal of wastes, the use of hydraulic fracturing fluids and historical industry operations and waste disposal practices. Any of these or other similar occurrences could result in the disruption or impairment of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution and substantial revenue losses. The location of our wells, gathering systems, pipelines and other facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

There are also significant risks associated with the operation of cryogenic natural gas processing plants such as the Black River Processing Plant owned by San Mateo and operated by us. Natural gas and NGLs are volatile and explosive and may include carcinogens. Damage to or improper operation of the Black River Processing Plant could result in an explosion or the discharge of toxic gases, which could result in significant damage claims, interrupt a revenue source and prevent us from processing some or all of the natural gas produced from our wells or third-party wells located in nearby asset areas. Furthermore, if we were unable to process such natural gas, we may be forced to flare natural gas from, or shut in, the affected wells for an indefinite period of time.

In addition, San Mateo's gathering, processing and transportation assets connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of, and our continuing access to, such third-party pipelines, processing facilities and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if San Mateo's costs to access and transport on these third-party pipelines significantly increase, its profitability could be reduced. If any such increase in costs occurs, if any of these pipelines or other midstream facilities become unable to receive, transport or process product, or if the volumes San Mateo gathers, processes or transports do not meet the product quality requirements of such pipelines or facilities, our and San Mateo's revenues and cash flows could be adversely affected.

Insurance Against All Operational Risks is Not Available to Us.

Insurance against all operational risks is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. Pollution and environmental risks generally are not fully insurable. In addition, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable prices or on commercially reasonable terms. Changes in the insurance markets due to various factors may make it more difficult for us to obtain certain types of coverage in the future. As a result, we may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and the insurance coverage we do obtain may not cover certain hazards or all potential losses that are currently covered, and may be subject to large deductibles. Losses and liabilities from uninsured and underinsured events and delays in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Because Our Reserves and Production Are Concentrated in a Few Core Areas, Problems in Production and Markets Relating to a Particular Area Could Have a Material Impact on Our Business.

Almost all of our current oil and natural gas production and our proved reserves are attributable to our properties in the Delaware Basin in Southeast New Mexico and West Texas, the Eagle Ford shale in South Texas and the Haynesville shale in Northwest Louisiana. In recent years, the Delaware Basin has become an area of increasing focus for us, and approximately 87% of our total oil and natural gas production for 2019 was attributable to our properties in the Delaware Basin. Since 2016, the vast majority of our capital expenditures have been allocated to the Delaware Basin. We expect that substantially all of our capital expenditures in 2020 will continue to be in the Delaware Basin, with the exception of amounts allocated to limited operations in our South Texas and Haynesville shale positions to maintain and extend leases and to participate in certain non-operated well opportunities.

The industry focus on the Delaware Basin may adversely impact our ability to gather, transport and process our oil and natural gas production due to significant competition for access to gathering systems, pipelines, processing facilities and oil, condensate and salt water trucking operations. For example, infrastructure constraints have in the past required, and may in the future require, us to flare natural gas occasionally, decreasing the volumes sold from our wells. Due to the concentration of our operations, we may be disproportionately exposed to the impact of delays or interruptions of production from our wells in our operating areas caused by transportation capacity constraints or interruptions, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions or plant closures for scheduled maintenance. Due to our concentration of properties in the Delaware Basin, we are also particularly exposed to any differential between benchmark prices of oil and natural gas and the wellhead price we receive for our production. See "—An Increase in the Differential between the NYMEX or Other Benchmark Prices of Oil and Natural Gas and the Wellhead Price We Receive for Our Production Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows."

Our operations may also be adversely affected by weather conditions and events such as hurricanes, tropical storms and inclement winter weather, resulting in delays in drilling and completions, damage to facilities and equipment and the inability to receive equipment or access personnel and products at affected job sites in a timely manner. For example, in recent years the Delaware Basin has experienced periods of severe winter weather that impacted many operators. In particular, weather conditions and freezing temperatures have resulted in power outages, curtailments in trucking, delays in drilling and completion of wells and other production constraints. Certain areas of the Delaware Basin have also experienced periods of severe flooding that impacted our operations as well as many other operators in the area, resulting in delays in drilling, completing and initiating production on certain wells. As we continue to focus our operations on the Delaware Basin, we may increasingly face these and other challenges posed by severe weather.

Similarly, certain areas of the Eagle Ford shale play are prone to severe tropical weather, such as Hurricane Harvey in August 2017, which caused many operators to shut in production. We experienced minor operational interruptions in our central and eastern Eagle Ford operations as a result of Hurricane Harvey, although future storms might cause more severe damage and interruptions or disrupt our ability to market production from our operating areas, including the Eagle Ford shale and the Delaware Basin.

Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. For example, our operations in the Delaware Basin are subject to particular restrictions on drilling activities based on environmental sensitivities and requirements and potash mining operations. Such delays, interruptions or restrictions could have a material adverse effect on our financial condition, results of operations and cash flows.

There Is No Guarantee That We Will Be Successful in Optimizing Our Spacing, Drilling and Completions Techniques in Order to Maximize Our Rate of Return, Cash Flow from Operations and Shareholder Value.

As we accumulate and process geological and production data, we attempt to create a development plan, including well spacing and completion design, that maximizes our rate of return, cash flow from operations and shareholder value. However, due to many factors, including some beyond our control, there is no guarantee that we will be able to find the optimal plan. Future drilling and completion efforts may impact production from existing wells, and parent-child effects may impact future well productivity as a result of timing, spacing proximity or other factors. If we are unable to design and implement an effective spacing, drilling and completions strategy, it may have a material adverse effect on our financial condition, results of operations and cash flows.

Certain of Our Properties Are in Areas That May Have Been Partially Depleted or Drained by Offset Wells, and Certain of Our Wells May Be Adversely Affected by Actions Other Operators May Take When Drilling, Completing or Operating Wells That They Own.

Certain of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Multi-Well Pad Drilling May Result in Volatility in Our Operating Results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not produced until other wells being drilled on the pad at the same time are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production from wells drilled on a given pad, which may cause volatility in our operating results. In addition, problems affecting one well could adversely affect production from other wells on the same pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production. Additionally, infrastructure expansion, including more complex facilities and takeaway capacity, could become challenging in project development areas. Managing capital expenditures for infrastructure expansion could cause economic constraints when considering design capacity.

We May Not Be Able to Generate Sufficient Cash to Service All of Our Indebtedness and May Be Forced to Take Other Actions to Satisfy Our Obligations under Applicable Debt Instruments, Which May Not Be Successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our Credit Agreement, the San Mateo Credit Facility and the indenture governing our outstanding senior notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations, which could have a material adverse effect on our financial condition and results of operations.

We May Incur Additional Indebtedness, Which Could Reduce Our Financial Flexibility, Increase Interest Expense and Adversely Impact Our Operations and Our Unit Costs.

As of February 28, 2020, the maximum facility amount under the Credit Agreement was $1.5 billion, the borrowing base was $900.0 million and our elected borrowing commitment was $700.0 million. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, maximum facility amount and elected borrowing commitment. At February 28, 2020, we had available borrowing capacity of approximately $399.0 million under our Credit Agreement (after giving effect to outstanding letters of credit). Our borrowing base is determined semi-annually by our lenders based primarily on the estimated value of our existing and future oil and natural gas reserves, but both we and our lenders can request one unscheduled redetermination between scheduled redetermination dates. Our Credit Agreement is secured by our interests in the majority of our oil and natural gas properties and contains covenants restricting our ability to incur additional indebtedness, sell assets, pay dividends and make certain investments. Since the borrowing base is subject to periodic redeterminations, if a redetermination resulted in a borrowing base that is less than our borrowings under the Credit Agreement, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or repay the deficit in equal installments over a period of six months. If we are required to do so, we may not have sufficient funds to fully make such repayments.

As of February 25, 2020, the facility amount under the San Mateo Credit Facility was $375.0 million, and San Mateo I had available borrowing capacity of approximately $70.8 million (after giving effect to outstanding letters of credit). The San Mateo Credit Facility includes an accordion feature, which could expand the commitments of the lenders to up to $400.0 million. The San Mateo Credit Facility is non-recourse with respect to Matador and its wholly-owned subsidiaries, as well as San Mateo II and its subsidiaries, but is guaranteed by San Mateo I's subsidiaries and secured by substantially all of San Mateo I's assets, including real property. The San Mateo Credit Facility contains covenants restricting San Mateo I's ability to incur additional indebtedness, sell assets, pay dividends and make certain investments.

In the future, subject to the restrictions in the indenture governing our outstanding senior notes and in other instruments governing our other outstanding indebtedness (including our Credit Agreement and the San Mateo Credit Facility), we may incur significant amounts of additional indebtedness, including under our Credit Agreement and the San Mateo Credit Facility, through the issuance of additional notes or otherwise, in order to develop our properties, fund acquisitions or invest in certain opportunities. Interest rates on such future indebtedness may be higher than current levels, causing our financing costs to increase accordingly.

A high level of indebtedness could affect our operations in several ways, including the following:

- requiring a significant portion of our cash flows to be used for servicing our indebtedness;
- increasing our vulnerability to general adverse economic and industry conditions;
- placing us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our level of indebtedness may prevent us from pursuing;
- restricting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate or other purposes; and
- increasing the risk that we may default on our debt obligations.

The Borrowing Base under Our Credit Agreement Is Subject to Periodic Redetermination, and We Are Subject to Interest Rate Risk under Our Credit Agreement and the San Mateo Credit Facility.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. We and the lenders may each request an unscheduled redetermination of the borrowing base once between scheduled redetermination dates. In addition, our lenders have the flexibility to reduce our borrowing base due to a variety of factors, some of which may be beyond our control. As of February 28, 2020, our borrowing base was $900.0 million, our elected borrowing commitment was $700.0 million and we had $255.0 million in outstanding borrowings under, and approximately $46.0 million in outstanding letters of credit issued pursuant to, the Credit Agreement. As of February 28, 2020, the maximum facility amount under the Credit Agreement was $1.5 billion. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, maximum facility amount and elected borrowing commitment. We could be required to repay a portion of any outstanding debt under the Credit Agreement to the extent that, after a redetermination, our outstanding borrowings at such time exceeded the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the Credit Agreement and an acceleration of the loans thereunder, requiring us to negotiate renewals, arrange new financing or sell significant assets, all of which could have a material adverse effect on our business and financial results.

Our earnings are exposed to interest rate risk associated with borrowings under our Credit Agreement and the San Mateo Credit Facility. Borrowings under the Credit Agreement may be in the form of a base rate loan or a Eurodollar loan. If we borrow funds as a base rate loan, such borrowings will bear interest at a rate equal to the greatest of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate (as defined in the Credit Agreement) on such day, plus 0.50%, and (iii) the daily adjusting LIBOR rate (as defined in the Credit Agreement), plus 1.0%, plus, in each case, an amount ranging from 0.25% to 1.25% per annum depending on the level of borrowings under the Credit Agreement. If we borrow funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (x) the reserve adjusted LIBOR rate (as defined in the Credit Agreement) plus (y) an amount ranging from 1.25% to 2.25% per annum depending on the level of borrowings under the Credit Agreement. If we have outstanding borrowings under our Credit Agreement and interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

Similarly, borrowings under the San Mateo Credit Facility may be in the form of a base rate loan or a Eurodollar loan. If San Mateo I borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the greatest of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate (as defined in the San Mateo Credit Facility) on such day, plus 0.50% and (iii) the Adjusted LIBO Rate (as defined in the San Mateo Credit Facility) plus

1.0% plus, in each case, an amount ranging from 0.50% to 1.50% per annum depending on San Mateo I's Consolidated Total Leverage Ratio (as defined in the San Mateo Credit Facility). If San Mateo I borrows funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (x) the Adjusted LIBO Rate for the chosen interest period plus (y) an amount ranging from 1.50% to 2.50% per annum depending on San Mateo I's Consolidated Total Leverage Ratio. If San Mateo I has outstanding borrowings under the San Mateo Credit Facility and interest rates increase, so will San Mateo I's interest costs, which may have a material adverse effect on San Mateo I's results of operations and financial condition.

As noted above, under the Credit Agreement and the San Mateo Credit Facility, borrowings in the form of Eurodollar loans accrue interest based on LIBOR. The use of LIBOR as a global reference rate is expected to be discontinued after 2021. Each of the Credit Agreement and the San Mateo Credit Facility specify that in the event that LIBOR cannot be determined or other conditions exist with respect to LIBOR, a replacement interest rate that gives due consideration to the then-prevailing market convention for determining a rate of interest for syndicated loans in the United States at such time may be established by the respective administrative agents, in consultation with us. If such an event occurs and we are unable to agree upon a replacement interest rate with our respective administrative agents, we could be unable to make borrowings in the form of Eurodollar loans and would have to borrow funds at the higher base rate, which could increase our cost of capital. Furthermore, the overall financial market may be disrupted as a result of the phase-out or replacement of LIBOR. An increase in our cost of capital or a disruption in the financial market could have an adverse effect on our business and financial condition.

The Terms of the Agreements Governing Our Outstanding Indebtedness May Restrict Our Current and Future Operations, Particularly Our Ability to Respond to Changes in Business or to Take Certain Actions.

Our Credit Agreement, the San Mateo Credit Facility and the indenture governing our senior notes contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. One or more of these agreements include covenants that, among other things, restrict our ability to:

- incur or guarantee additional debt or issue certain types of preferred stock;
- pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness;
- transfer or sell assets;
- make certain investments;
- create certain liens;
- enter into agreements that restrict dividends or other payments from our Restricted Subsidiaries (as defined in the indenture) to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates; and
- create unrestricted subsidiaries.

A breach of any of these covenants could result in an event of default under our Credit Agreement, the San Mateo Credit Facility and the indenture governing our outstanding senior notes. For example, our Credit Agreement requires us to maintain a debt to EBITDA ratio, which is defined as debt outstanding (net of up to $50 million of cash or cash equivalents) divided by a rolling four quarter EBITDA calculation, of 4.00 or less. Low oil and natural gas prices or a decline in our oil or natural gas production may adversely impact our EBITDA, cash flows and debt levels, and therefore our ability to comply with this covenant.

Similarly, the San Mateo Credit Facility requires San Mateo I to meet a debt to EBITDA ratio, which is defined as consolidated total funded indebtedness outstanding (as defined in the San Mateo Credit Facility) divided by a rolling four quarter EBITDA calculation, of 5.00 or less, subject to certain exceptions. The San Mateo Credit Facility also requires San Mateo I to maintain an interest coverage ratio, which is defined as a rolling four quarter EBITDA calculation divided by San Mateo I's consolidated interest expense, of 2.50 or more. Lower revenues as a result of less volumes than anticipated, or otherwise, or an increase in interest rates may adversely impact San Mateo I's EBITDA and interest expense, and therefore San Mateo I's ability to comply with these covenants.

Upon the occurrence of an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If indebtedness under our Credit Agreement, the San Mateo Credit Facility or the indenture governing our outstanding senior notes is accelerated, there can be no assurance that we will have sufficient assets to repay such indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements could adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Our Credit Rating May Be Downgraded, Which Could Reduce Our Financial Flexibility, Increase Interest Expense and Adversely Impact Our Operations.

As of February 25, 2020, our corporate credit rating from Standard & Poor's Rating Services was "B+" and our corporate credit rating from Moody's Investors Service was "B1." We cannot assure you that our credit ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Any future downgrade could increase the cost of any indebtedness incurred in the future.

Any increase in our financing costs resulting from a credit rating downgrade could adversely affect our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate or other purposes. If a credit rating downgrade were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, our results of operations could be materially adversely affected.

We Depend upon Several Significant Purchasers for the Sale of Most of Our Oil and Natural Gas Production. The Loss of One or More of These Purchasers Could, Among Other Factors, Limit Our Access to Suitable Markets for the Oil and Natural Gas We Produce.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. For the years ended December 31, 2019, 2018 and 2017, we had two, four and four significant purchasers, respectively, that collectively accounted for approximately 67%, 60% and 60%, respectively, of our total oil, natural gas and NGL revenues. We cannot assure you that we will continue to have ready access to suitable markets for our future production. If we lost one or more of these customers and were unable to sell our production to other customers on terms we consider acceptable, it could materially and adversely affect our business, financial condition, results of operations and cash flows.

Financial Difficulties Encountered by Our Oil and Natural Gas Purchasers, Third-Party Operators or Other Third Parties Could Decrease Our Cash Flows from Operations and Adversely Affect the Exploration and Development of Our Prospects and Assets.

We derive most of our revenues from the sale of our oil, natural gas and NGLs to unaffiliated third-party purchasers, independent marketing companies and midstream companies. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We cannot predict the extent to which counterparties' businesses would be impacted if oil and natural gas prices decline, such prices remain depressed for a sustained period of time or other conditions in our industry were to deteriorate. Any delays in payments from our purchasers caused by financial problems encountered by them could have an immediate negative effect on our results of operations and cash flows.

Liquidity and cash flow problems encountered by our working interest co-owners or the third-party operators of our non-operated properties may prevent or delay the drilling of a well or the development of a project. Our working interest co-owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a farmout party, we would have to find a new farmout party or obtain alternative funding in order to complete the exploration and development of the prospects subject to a farmout agreement. In the case of a working interest owner, we could be required to pay the working interest owner's share of the project costs. If we are not able to obtain the capital necessary to fund either of these contingencies or find a new farmout party, our results of operations and cash flows could be negatively affected.

The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows.

Shortages or the high cost of drilling rigs, completion equipment and services, personnel or supplies, including sand and other proppants, could delay or adversely affect our operations. When drilling activity in the United States or a particular operating area increases, associated costs typically also increase, including those costs related to drilling rigs, equipment, supplies, including sand and other proppants, and personnel and the services and products of other industry vendors. These costs may increase, and necessary equipment, supplies and services may become unavailable to us at economical prices. Should this increase in costs occur, we may delay drilling or completion activities, which may limit our ability to establish and replace reserves, or we may incur these higher costs, which may negatively affect our business, financial condition, results of operations and cash flows. In addition, should oil and natural gas prices decline, third-party service providers may face financial difficulties and be unable to provide services. A reduction in the number of service providers available to us may negatively impact our ability to retain qualified service providers, or obtain such services at costs acceptable to us.

In addition, the demand for hydraulic fracturing services from time to time exceeds the availability of fracturing equipment and crews across the industry and in certain operating areas in particular. The accelerated wear and tear of hydraulic fracturing equipment due to its deployment in unconventional oil and natural gas fields characterized by longer lateral lengths and larger numbers of fracturing stages could further amplify such an equipment and crew shortage. If demand for fracturing services were to increase or the supply of fracturing equipment and crews were to decrease, higher costs or delays in procuring these services could result, which could adversely affect our business, financial condition, results of operations and cash flows.

If We Are Unable to Acquire Adequate Supplies of Water for Our Drilling and Hydraulic Fracturing Operations or Are Unable to Dispose of the Water We Use at a Reasonable Cost and Pursuant to Applicable Environmental Rules, Our Ability to Produce Oil and Natural Gas Commercially and in Commercial Quantities Could Be Impaired.

We use a substantial amount of water in our drilling and hydraulic fracturing operations. Our inability to obtain sufficient amounts of water at reasonable prices, or treat and dispose of water after drilling and hydraulic fracturing, could adversely impact our operations. In recent years, Southeast New Mexico and West Texas have experienced severe drought. As a result, we may experience difficulty in securing the necessary volumes of water for our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development and production of oil and natural gas. Furthermore, future environmental regulations and permitting requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells could increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our business, financial condition, results of operations and cash flows.

If Regulatory Changes Prevent Our Ability to Continue to Pool Wells in the Manner We Have Been, It Could Have a Material Adverse Impact on Our Future Production Results.

In Texas, allocation wells allow an operator to drill a horizontal well under two or more leaseholds that are not pooled or across multiple existing pooled units. In New Mexico, operators are able to pool multiple spacing units in order to drill a single horizontal well across several leaseholds. We are active in drilling and producing both allocation wells in Texas and pooled spacing unit wells in New Mexico. If there are regulatory changes with regard to such wells, the applicable state agency denies or significantly delays the permitting of such wells, legislation is enacted that negatively impacts the current process under which such wells are permitted or litigation challenges the regulatory schemes pursuant to which such wells are permitted, it could have an adverse impact on our ability to drill long horizontal lateral wells on some of our leases, which in turn could have a material adverse impact on our anticipated future production.

Unless We Replace Our Oil and Natural Gas Reserves, Our Reserves and Production Will Decline, Which Would Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The rate of production from our oil and natural gas properties declines as our reserves are depleted. Our future oil and natural gas reserves and production and, therefore, our income and cash flow are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional oil and natural gas producing properties. We are currently focusing primarily on increasing our production and reserves from the Delaware Basin, an area with intense competition and industry activity. As a result of this activity, we may have difficulty growing our current production or acquiring new properties in this area and may experience such difficulty in other areas in the future. During periods of low oil and/or natural gas prices, existing reserves may no longer be economic, and it will become more difficult to raise the capital necessary to finance expansion activities. If we are unable to replace our current and future production, our reserves will decrease, and our business, financial condition, results of operations and cash flows would be adversely affected.

The Marketability of Our Production Is Dependent upon Oil, Natural Gas and NGL Gathering, Processing and Transportation Facilities, and the Unavailability of Satisfactory Oil, Natural Gas and NGL Gathering, Processing and Transportation Arrangements Could Have a Material Adverse Effect on Our Revenue.

The unavailability of satisfactory oil, natural gas and NGL gathering, processing and transportation arrangements may hinder our access to oil, natural gas and NGL markets or delay production from our wells. The availability of a ready market for our oil, natural gas and NGL production depends on a number of factors, including the demand for, and supply of, oil, natural gas and NGLs and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities and oil and condensate trucking operations. Such systems and operations include those of San Mateo, as well as other systems and operations owned and operated by third parties. The continuing operation of, and our continuing access to, third-party systems and operations is outside our control. Regardless of who operates the midstream systems or operations upon which we rely, our failure to obtain these services on acceptable terms could materially harm our business. In addition, certain of these gathering systems, pipelines and processing facilities, particularly in the Delaware Basin, may be outdated or in need of repair and subject to higher rates of line loss, failure and breakdown. Furthermore, such facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. Due to our concentration of properties in the Delaware Basin, we are also particularly exposed to any differential between benchmark prices of oil and natural gas and the wellhead price we receive for our production. See "—An Increase in the Differential between the NYMEX or Other Benchmark Prices of Oil and Natural Gas and the Wellhead Price We Receive for Our Production Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows."

We may be required to shut in wells for lack of a market or because of inadequate or unavailable pipelines, gathering systems, processing facilities or trucking capacity. If that were to occur, we would be unable to realize revenue from those wells until production arrangements were made to deliver our production to market. Furthermore, if we were required to shut in wells we might also be obligated to pay shut-in royalties to certain mineral interest owners in order to maintain our leases. In addition, if we are unable to market our production we may be required to flare natural gas, which would decrease the volumes sold from our wells, and, in certain circumstances, would require us to pay royalties on such flared natural gas.

The disruption of our own or third-party facilities due to maintenance, weather or other factors could negatively impact our ability to market and deliver our oil, natural gas and NGLs. If our costs to access and transport on these pipelines significantly increase, our profitability could be reduced. Third parties control when or if their facilities are restored and what prices will be charged. In the past, we have experienced pipeline and natural gas processing interruptions and capacity and infrastructure constraints associated with natural gas production, which has, among other things, required us to flare natural gas occasionally. While we have entered into natural gas processing and transportation agreements covering the anticipated natural gas production from a significant portion of our Delaware Basin acreage in Southeast New Mexico and West Texas, no assurance can be given that these agreements will alleviate these issues completely, and we may be required to pay deficiency payments under such agreements if we do not meet the gathering, disposal or processing commitments, as applicable. We may experience similar interruptions and processing capacity constraints as we continue to explore and develop our Wolfcamp, Bone Spring and other liquids-rich plays in the Delaware Basin in 2020. If we were required to shut in our production or flare our natural gas for long periods of time due to pipeline interruptions or lack of processing facilities or capacity of these facilities, it could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We Conduct a Portion of Our Operations through Joint Ventures, Which Subjects Us to Additional Risks That Could Have a Material Adverse Effect on the Success of These Operations, Our Financial Position, Results of Operations or Cash Flows.

We own and operate substantially all of our midstream assets in the Delaware Basin through San Mateo, and we may enter into other joint venture arrangements in the future. The nature of a joint venture requires us to share a portion of control with unaffiliated third parties. If our joint venture partners do not fulfill their contractual and other obligations, the affected joint venture may be unable to operate according to its business plan, and we may be required to increase our level of financial commitment or seek third-party capital, which could dilute our ownership in the applicable joint venture. If we do not timely meet our financial commitments or otherwise comply with our joint venture agreements, our ownership of and rights with respect to the applicable joint venture may be reduced or otherwise adversely affected. Furthermore, there can be no assurance that any joint venture will be successful or generate cash flows at the level we have anticipated, or at all. Differences in views among joint venture participants could also result in delays in business decisions or otherwise, failures to agree on major issues, operational inefficiencies and impasses, litigation or other issues. We provide management functions for San Mateo and may provide such services for future joint venture arrangements, which may require additional time and attention of management or require us to hire or contract additional personnel. Third parties may also seek to hold us liable for a joint venture's liabilities. These issues or any other difficulties that cause a joint venture to deviate from its original business plan could have a material adverse effect on our financial condition, results of operations and cash flows.

Because of the Natural Decline in Production in the Regions of San Mateo's Midstream Operations, San Mateo's Long-Term Success Depends on its Ability to Obtain New Sources of Products, Which Depends on Certain Factors Beyond San Mateo's Control. Any Decrease in Supplies to its Midstream Facilities Could Adversely Affect San Mateo's Business and Operating Results.

San Mateo's midstream facilities are or will be connected to oil and natural gas wells operated by us or by third parties from which production will naturally decline over time, which means that the cash flows associated with these sources of oil, natural gas, NGLs and produced water will also decline over time. Some of these third parties are not subject to minimum volume commitments. To maintain or increase throughput levels on San Mateo's gathering systems and the utilization rate at its other midstream facilities, San Mateo must continually obtain new sources of products. San Mateo's ability to obtain additional sources of oil, natural gas, NGLs and produced water depends, in part, on the level of successful drilling and production activity near its gathering and transportation systems and other midstream facilities. San Mateo has no control over the level of third-party activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, San Mateo has no control over third-party producers or their drilling or production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations, the availability of drilling rigs, other production and development costs and the availability and cost of capital.

We Have Entered into Certain Long-Term Contracts That Require Us to Pay Fees to Our Service Providers Based on Minimum Volumes Regardless of Actual Volume Throughput and That May Limit Our Ability to Use Other Service Providers.

From time to time, we have entered into and may in the future enter into certain oil, natural gas or salt water gathering or transportation agreements, natural gas processing agreements, salt water disposal agreements or similar commercial arrangements with midstream companies, including San Mateo. Certain of these agreements require us to meet minimum volume commitments, often regardless of actual throughput. Lower commodity prices may lead to reductions in our drilling program, which may result in insufficient production to fulfill our obligations under these agreements. As of December 31, 2019, our long-term contractual obligations under agreements with minimum volume commitments totaled approximately $1.2 billion over the terms of the agreements. If we have insufficient production to meet the minimum volume commitments under any of these agreements, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect on our results of operations.

Pursuant to certain of our agreements with midstream companies, we have dedicated our current and future leasehold interests in certain of our asset areas to counterparties. As a result, we will be limited in our ability to use other gathering, processing, disposal and transportation service providers, even if such service providers are able to offer us more favorable pricing or more efficient service.

We Do Not Own All of the Land on Which Our Midstream Assets Are Located, Which Could Disrupt Our Operations.

We do not own all of the land on which our midstream assets are located, and we are therefore subject to the possibility of more onerous terms and/or increased costs or royalties to retain necessary land access if we do not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, leases or otherwise, could cause us to cease operations on the affected land or find alternative locations for our operations at increased costs, each of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Construction of Midstream Projects Subjects Us to Risks of Construction Delays, Cost Over-Runs, Limitations on Our Growth and Negative Effects on Our Financial Condition, Results of Operations, Cash Flows and Liquidity.

From time-to-time, we, through San Mateo or otherwise, plan and construct midstream projects, some of which may take a number of months before commercial operation, such as construction of oil, natural gas and water gathering systems, construction of natural gas processing plants, drilling of commercial salt water disposal wells and construction of related facilities. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, government and regulatory approval, compliance with laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on our business, results of operations, liquidity and financial condition. The construction of salt water disposal facilities, pipelines and gathering and processing facilities requires the expenditure of significant amounts of capital, which may exceed our estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and financial condition could be adversely affected. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

Our Oil and Natural Gas Reserves Are Estimated and May Not Reflect the Actual Volumes of Oil and Natural Gas We Will Recover, and Significant Inaccuracies in These Reserves Estimates or Underlying Assumptions Will Materially Affect the Quantities and Present Value of Our Reserves.

The process of estimating accumulations of oil and natural gas is complex and inexact due to numerous inherent uncertainties. This process relies on interpretations of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. This process also requires certain economic assumptions related to, among other things, oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserves estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the judgment of the persons preparing the estimate; and
- the accuracy of the assumptions used.

The accuracy of any estimates of proved oil and natural gas reserves generally increases with the length of production history. Due to the limited production history of many of our properties, the estimates of future production associated with these properties may be subject to greater variance to actual production than would be the case with properties having a longer production history. As our wells produce over time and more data becomes available, the estimated proved reserves will be redetermined on at least an annual basis and may be adjusted to reflect new information based upon our actual production history, results of exploration and development, prevailing oil and natural gas prices and other factors.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas most likely will vary from our estimates. It is possible that future production declines in our wells may be greater than we have estimated. Any significant variance from our estimates could materially affect the quantities and present value of our reserves.

The Calculated Present Value of Future Net Revenues from Our Proved Oil and Natural Gas Reserves Will Not Necessarily Be the Same as the Current Market Value of Our Estimated Oil and Natural Gas Reserves.

It should not be assumed that the present value of future net cash flows included in this Annual Report is the current market value of our estimated proved oil and natural gas reserves. As required by SEC rules and regulations, the estimated discounted future net cash flows from proved oil and natural gas reserves are based on current costs held constant over time without escalation and on commodity prices using an unweighted arithmetic average of first-day-of-the-month index prices, appropriately adjusted, for the 12-month period immediately preceding the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs used for these estimates and will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual costs and timing of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under U.S. generally accepted accounting principles ("GAAP") is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and natural gas industry in general.

Approximately 58% of Our Total Proved Reserves at December 31, 2019 Consisted of Undeveloped and Developed Non-Producing Reserves, and Those Reserves May Not Ultimately Be Developed or Produced.

At December 31, 2019, approximately 58% of our total proved reserves were undeveloped and less than 1% of our total proved reserves were developed non-producing. Our undeveloped and/or developed non-producing reserves may never be developed or produced or such reserves may not be developed or produced within the time periods we have projected or at the costs we have estimated. SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they are related to wells scheduled to be drilled within five years after the date of booking. Delays in the development of our reserves or increases in costs to drill and develop such reserves would reduce the present value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves, resulting in some projects becoming uneconomical and reducing our total proved reserves. In addition, delays in the development of reserves or declines in the oil and/or natural gas prices used to estimate proved reserves in the future could cause us to have to reclassify a portion of our proved reserves as unproved reserves. Any reduction in our proved reserves caused by the reclassification of undeveloped or developed non-producing reserves could materially affect our business, financial condition, results of operations and cash flows.

Our Identified Drilling Locations Are Scheduled over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling.

Our management team has identified and scheduled drilling locations in our operating areas over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including oil and natural gas prices, assessment of risks, costs, drilling results, reservoir heterogeneities, the availability of equipment and capital, approval by regulators, lease terms, seasonal conditions and the actions of other operators. Additionally, as lateral lengths greater than one mile become increasingly common in the Delaware Basin, we will have to cooperate with other operators to ensure that our acreage is included in drilling units or otherwise developed. The final determination on whether to drill any of the identified locations will be dependent upon the factors described elsewhere in this Annual Report as well as, to some degree, the results of our drilling activities with respect to our established drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe, or at all, or if we will be able to economically produce hydrocarbons from these or any other potential drilling locations. Our actual drilling activities may be materially different from our current expectations, which could adversely affect our business, financial condition, results of operations and cash flows.

Certain of Our Unproved and Unevaluated Acreage Is Subject to Leases That Will Expire over the Next Several Years Unless Production Is Established on Units Containing the Acreage.

At December 31, 2019, we had leasehold interests in approximately 42,400 net acres across all of our areas of interest that are not currently held by production and are subject to leases with primary or renewed terms that expire prior to 2025. Unless we establish and maintain production, generally in paying quantities, on units containing these leases during their terms or we renew such leases, these leases 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. In addition, on certain portions of our acreage, third-party leases, or top leases, may have been taken and could become immediately effective if our leases expire. If our leases expire or we are unable to renew such leases, we will lose our right to develop the related properties. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business, financial condition, results of operations and cash flows.

The 2-D and 3-D Seismic Data and Other Advanced Technologies We Use Cannot Eliminate Exploration Risk, Which Could Limit Our Ability to Replace and Grow Our Reserves and Materially and Adversely Affect Our Results of Operations and Cash Flows.

We employ visualization and 2-D and 3-D seismic images to assist us in exploration and development activities where applicable. These techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. We could incur losses by drilling unproductive wells based on these technologies. Furthermore, seismic and geological data can be expensive to license or obtain, and we may not be able to license or obtain such data at an acceptable cost. Poor results from our exploration and development activities could limit our ability to replace and grow reserves and adversely affect our business, financial condition, results of operations and cash flows.

Competition in the Oil and Natural Gas Industry Is Intense, Making It More Difficult for Us to Acquire Properties, Market Oil and Natural Gas, Provide Midstream Services and Secure Trained Personnel.

Competition is intense in virtually all facets of our business. Our ability to acquire additional prospects and to find and develop reserves in the future will depend in part on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Similarly, our midstream business, and particularly the success of San Mateo, depends in part on our ability to compete with other midstream service companies to attract third-party customers to our midstream facilities. San Mateo competes with other midstream companies that provide similar services in its areas of operations, and such companies may have legacy relationships with producers in those areas and may have a longer history of efficiency and reliability. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased in recent years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, developing midstream assets, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our Competitors May Use Superior Technology and Data Resources That We May Be Unable to Afford or That Would Require a Costly Investment by Us in Order to Compete with Them More Effectively.

Our industry is subject to rapid and significant advancements in technology, including the introduction of new products, equipment and services using new technologies and databases. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, many of our competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we use or that we may implement in the future may become obsolete, and our operations may be adversely affected.

Strategic Relationships upon Which We May Rely Are Subject to Change, Which May Diminish Our Ability to Conduct Our Operations.

Our ability to explore, develop and produce oil and natural gas resources successfully, acquire oil and natural gas interests and acreage and conduct our midstream activities depends on our developing and maintaining close working relationships with industry participants and on our ability to select and evaluate suitable acquisition opportunities in a highly competitive environment. These relationships are subject to change and, if they do, our ability to grow may be impaired.

To develop our business, we endeavor to use the business relationships of our management, Board of Directors and special Board advisors to enter into strategic relationships, which may take the form of contractual arrangements with other oil and natural gas companies and service companies, including those that supply equipment and other resources that we expect to use in our business, as well as midstream companies and certain financial institutions. We may not be able to establish these strategic relationships, or if established, we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to incur or undertake in order to fulfill our obligations to these partners or maintain our relationships. If our strategic relationships are not established or maintained, our business prospects may be limited, which could diminish our ability to conduct our operations.

We Have Limited Control over Activities on Properties We Do Not Operate.

We are not the operator on some of our properties, particularly in the Haynesville shale. We also have other non-operated acreage positions in Northwest Louisiana, Southeast New Mexico, West Texas and South Texas. Because we are not the operator for these properties, our ability to exercise influence over the operations of these properties or their associated costs is limited. Our dependence on the operators and other working interest owners of these projects and our limited ability to influence operations and associated costs, or control the risks, could materially and adversely affect the drilling results, reserves and future cash flows from these properties. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors, including:

- the timing and amount of capital expenditures;
- the operator’s expertise and financial resources;
- the rate of production of reserves, if any;
- approval of other participants in drilling wells; and
- selection and implementation or execution of technology.

In areas where we do not have the right to propose the drilling of wells, we may have limited influence on when, how and at what pace our properties in those areas are developed. Further, the operators of those properties may experience financial problems in the future or may sell their rights to another operator not of our choosing, both of which could limit our ability to develop and monetize the underlying oil or natural gas reserves. In addition, the operators of these properties may elect to curtail the oil or natural gas production or to shut in the wells on these properties during periods of low oil or natural gas prices, and we may receive less than anticipated or no production and associated revenues from these properties until the operator elects to return them to production.

A Component of Our Growth May Come through Acquisitions, and Our Failure to Identify or Complete Future Acquisitions Successfully Could Reduce Our Earnings and Hamper Our Growth.

We may be unable to identify properties for acquisition or to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. The pursuit and completion of acquisitions may be dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to grow through acquisitions will require us to continue to invest in operations and financial and management information systems and to attract, retain, motivate and effectively manage our employees. In addition, if we are not successful in identifying and acquiring properties, our earnings could be reduced and our growth could be restricted.

In addition, we may be unable to successfully integrate potential acquisitions into our existing operations. The inability to manage the integration of acquisitions effectively could reduce our focus on subsequent acquisitions and current operations, and could negatively impact our results of operations and growth potential. Members of our senior management team may be required to devote considerable amounts of time to the integration process, which will decrease the time they will have to manage our business.

Furthermore, our decision to acquire properties that are substantially different in operating or geologic characteristics or geographic locations from areas with which our staff is familiar may impact our productivity in such areas. Our financial condition, results of operations and cash flows may fluctuate significantly from period to period as a result of the completion of significant acquisitions during particular periods.

We may engage in bidding and negotiation to complete successful acquisitions. We may be required to alter or increase substantially our capitalization to finance these acquisitions through the use of cash on hand, the issuance of debt or equity securities, the sale of production payments, the sale or joint venture of midstream assets or oil and natural gas producing assets or acreage, the borrowing of funds or otherwise. Our Credit Agreement, the San Mateo Credit Facility and the indenture governing our outstanding senior notes include covenants limiting our ability to incur additional debt. If we were to proceed with one or more acquisitions involving the issuance of our common stock, our shareholders would suffer dilution of their interests.

We May Purchase Oil and Natural Gas Properties with Liabilities or Risks That We Did Not Know about or That We Did Not Assess Correctly, and, as a Result, We Could Be Subject to Liabilities That Could Adversely Affect Our Results of Operations.

Before acquiring oil and natural gas properties, we assess the potential reserves, future oil and natural gas prices, operating costs, potential environmental liabilities and other factors relating to the properties. However, our review involves many assumptions and estimates, and their accuracy is inherently uncertain. As a result, we may not discover all existing or potential problems associated with the properties we buy. We may not become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not generally perform inspections on every well or property, and we may not be able to observe mechanical and environmental problems even when we conduct an inspection. The seller may not be willing or financially able to give us contractual protection against any identified problems, and we may decide to assume environmental and other liabilities in connection with properties we acquire. If we acquire properties with risks or liabilities we did not know about or that we did not assess correctly, our financial condition, results of operations and cash flows could be adversely affected as we settle claims and incur cleanup costs related to these liabilities.

Our Ability to Complete Dispositions of Assets, or Interests in Assets, May Be Subject to Factors Beyond Our Control, and in Certain Cases We May Be Required to Retain Liabilities for Certain Matters.

From time to time, we may sell an interest in a strategic asset for the purpose of assisting or accelerating the asset's development. In addition, we regularly review our property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect our ability to dispose of such interests or nonstrategic assets or complete announced dispositions, including the receipt of approvals of governmental agencies or third parties and the identification of purchasers willing to acquire the interests or purchase the nonstrategic assets on terms and at prices acceptable to us.

Sellers typically retain certain liabilities or indemnify buyers for certain pre-closing matters, such as matters of litigation, environmental contingencies, royalty obligations and income taxes. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

We May Incur Losses or Costs as a Result of Title Deficiencies in the Properties in Which We Invest.

If an examination of the title history of a property that we have purchased reveals an oil and natural gas lease has been purchased in error from a person who is not the mineral interest owner or if the property has other title deficiencies, our interest would likely be worth less than what we paid or may be worthless. In such an instance, all or part of the amount paid for such oil and natural gas lease as well as all or part of any royalties paid pursuant to the terms of the lease prior to the discovery of the title defect would be lost.

It is not our practice in all acquisitions of oil and natural gas leases, or undivided interests in oil and natural gas leases, to undergo the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease. Rather, in certain acquisitions we rely upon the judgment of oil and natural gas lease brokers and/or landmen who perform the field work by examining records in the appropriate governmental office before attempting to acquire a lease on a specific mineral interest.

Prior to the drilling of an oil and natural gas well, however, it is standard industry practice for the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, and such title review and curative work entails expense, which may be significant and difficult to accurately predict. Our failure to cure any title defects may adversely impact our ability to increase production and reserves. In the future, we may suffer a monetary loss from title defects or title failure. Additionally, unproved and unevaluated acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss that could adversely affect our financial condition, results of operations and cash flows.

We May Be Required to Write Down the Carrying Value of Our Proved Properties under Accounting Rules, and These Write-Downs Could Adversely Affect Our Financial Condition.

There is a risk that we will be required to write down the carrying value of our oil and natural gas properties when oil or natural gas prices are low or are declining. In addition, non-cash write-downs may occur if we have:

- downward adjustments to our estimated proved reserves;
- increases in our estimates of development costs; or
- deterioration in our exploration and development results.

We periodically review the carrying value of our oil and natural gas properties under full-cost accounting rules. Under these rules, the net capitalized costs of oil and natural gas properties less related deferred income taxes may not exceed a cost center ceiling that is calculated by determining the present value, based on constant prices and costs projected forward from a single point in time, of estimated future after-tax net cash flows from proved reserves, discounted at 10%. If the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceed the cost center ceiling, we must charge the amount of this excess to operations in the period in which the excess occurs. We may not reverse write-downs even if prices increase in subsequent periods. A write-down does not affect net cash flows from operating activities, liquidity or capital resources, but it does reduce the book value of our net tangible assets, retained earnings and shareholders' equity, and could lower the value of our common stock.

Hedging Transactions, or the Lack Thereof, May Limit Our Potential Gains and Could Result in Financial Losses.

To manage our exposure to price risk, we, from time to time, enter into hedging arrangements, using primarily "costless collars" or "swaps" with respect to a portion of our future production. Costless collars provide us with downside price protection through the purchase of a put option, which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially "costless" to us. Three-way costless collars also provide us with downside price protection through the purchase of a put option, but they also allow us to participate in price upside through the purchase of a call option. The purchase of both the put option and call option are financed through the sale of a call option. Because the proceeds from the call option sale are used to offset the cost of the purchased put and call options, these arrangements are also initially "costless" to us. In the case of a costless collar, the put option and the call option or options have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over the specified period, providing downside price protection. The goal of these and other hedges is to lock in a range of prices in the case of collars or a fixed price in the case of swaps so as to mitigate price volatility and increase the predictability of cash flows. These transactions limit our potential gains if oil, natural gas or NGL prices rise above the maximum price established by the call option or swap as applicable, and may offer protection if prices fall below the minimum price established by the put option or swap, as applicable, only to the extent of the volumes then hedged.

In addition, hedging transactions may expose us to the risk of financial loss in certain other circumstances, including instances in which our production is less than expected or the counterparties to our put and call option or swap contracts fail to perform under the contracts. Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair its ability to perform under the terms of the contracts. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform under contracts with us. Even if we do accurately predict sudden changes, our ability to mitigate that risk may be limited depending upon market conditions.

Furthermore, there may be times when we have not hedged our production when, in retrospect, it would have been advisable to do so. Decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and NGL prices, and we may not always employ the optimal hedging strategy. We may employ hedging strategies in the future that differ from those that we have used in the past, and neither the continued application of our current strategies nor our use of different hedging strategies may be successful. As of February 25, 2020, we had approximately 45% of our estimated 2020 oil production hedged in addition to oil basis hedges for approximately 65% of our 2020 Delaware Basin oil production. As of February 25, 2020, we had no hedges in place for natural gas or NGLs.

An Increase in the Differential between the NYMEX or Other Benchmark Prices of Oil and Natural Gas and the Wellhead Price We Receive for Our Production Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The prices we receive for our oil and natural gas production often reflect a discount to the relevant benchmark prices, such as the NYMEX West Texas Intermediate oil price or the NYMEX Henry Hub natural gas price. The difference between the benchmark price and the price we receive is called a differential. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could adversely affect our business, financial condition, results of operations and cash flows.

For the first nine months of 2019, most of our natural gas production from the Delaware Basin was sold based upon prices established at the Waha Hub in far West Texas. The price differential between the Waha Hub index and the Henry Hub index reached highs of greater than $4.00 per MMBtu for a brief period at the end of 2018, but narrowed to between $1.00 and $2.00 per MMBtu at the beginning of 2019 and remained there throughout much of the first quarter. The natural gas basis differentials widened significantly in April 2019 for a short period of time, including a few days when natural gas was being sold at Waha for negative prices as high as ($7.00) to ($9.00) per MMBtu on a daily market basis, resulting, in part, from a number of simultaneous outages and maintenance projects impacting major pipelines in the area. In response to these basis differentials, we temporarily shut in certain high gas-oil ratio wells to mitigate the impact of these negative prices on our results. Despite improving during the second half of 2019, beginning in the fourth quarter, the Waha basis differentials widened further at times, and natural gas prices at the Waha hub were slightly negative on certain days in late December 2019. In early 2020, the outlook for the Waha basis differentials has deteriorated further.

Similarly, much of our oil production from the Delaware Basin was sold based on prices established in Midland, Texas. The price differential between the West Texas Intermediate oil price and the oil price at the Midland Hub, also known as the Midland-Cushing (Oklahoma) differential, was approximately $5.00 per Bbl at the beginning of 2019. This oil price differential narrowed to less than $1.00 per Bbl during the first quarter of 2019 but widened again during the second quarter to levels experienced at the beginning of the year. The Midland-Cushing (Oklahoma) oil price differential narrowed again in the third quarter of 2019, became positive late in the third quarter and remained positive throughout the fourth quarter of 2019, although it is possible that the differential could become negative again at certain times during 2020. We have limited oil basis hedges in place to mitigate our exposure to these oil price differentials during 2020, 2021 and 2022, and we have no derivative contracts in place to mitigate our exposure to these natural gas price differentials.

These widening oil and natural gas basis differentials are largely attributable to industry concerns regarding the near-term sufficiency of pipeline takeaway capacity for oil, natural gas and NGL production in the Delaware Basin. If we do experience any interruptions with takeaway capacity or NGL fractionation, our oil and natural gas revenues, business, financial condition, results of operations and cash flows could be adversely affected.

We anticipate that the volatility in these oil and natural gas price differentials could persist throughout 2020 or longer until additional oil and natural gas pipeline capacity from West Texas to the Texas Gulf Coast and other end markets is completed. We can provide no assurances as to how long these volatile differentials may persist, and as noted above, these price differentials could widen further in future periods. Should we experience future periods of negative pricing for natural gas as we did during the second quarter of 2019, we may temporarily shut in certain high gas-oil ratio wells and take other actions to mitigate the impact on our realized natural gas prices and results.

Approximately 26% of Our Leasehold and Mineral Acres in the Delaware Basin Are Located on Federal Lands, Which Are Subject to Administrative Permitting Requirements and Potential Federal Legislation, Regulation and Orders That May Limit or Restrict Oil and Natural Gas Operations on Federal Lands.

At December 31, 2019, Matador held approximately 128,200 net leasehold and mineral acres in the Delaware Basin in Eddy and Lea Counties, New Mexico and in Loving County, Texas, of which approximately 33,000 net acres, or about 26%, were on federal lands administered by the BLM. In addition to permits issued by state and local authorities, oil and natural gas activities on federal lands also require permits from the BLM. Permitting for oil and natural gas activities on federal lands can take significantly longer than the permitting process for oil and natural gas activities not located on federal lands. Delays in obtaining necessary permits can disrupt our operations and have an adverse effect on our business. These BLM leases contain relatively standardized terms and require compliance with detailed regulations and orders, which are subject to change. These operations are also subject to BLM rules regarding engineering and construction specifications for production facilities, safety procedures, the valuation of production, the payment of royalties, the removal of facilities, the posting of bonds, hydraulic fracturing, the control of air emissions and other areas of environmental protection. These rules could result in increased compliance costs for our operations, which in turn could have an adverse effect on our business and results of operations. Under certain circumstances, the BLM may require our operations on federal leases to be suspended or terminated. In addition, litigation related to leasing and permitting of federal lands could also restrict, delay or limit our ability to conduct operations on our federal leasehold or acquire additional federal leasehold. Certain candidates seeking the office of the President of the United States in 2020 have proposed a ban of new leases for production of minerals on federal properties, which would also limit our ability to acquire additional federal leasehold. At the federal level, various policy makers, regulatory agencies and political candidates, including presidential candidates, have also proposed restrictions on hydraulic fracturing, including its outright prohibition. It is possible that any such restrictions on hydraulic fracturing may particularly target activity on federal lands. Any federal legislation, regulations or orders intended to limit or restrict oil and natural gas operations on federal lands, if enacted, could have an adverse impact on our business, financial condition, results of operations and cash flows.

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

We Are Subject to Government Regulation and Liability, Including Complex Environmental Laws, Which Could Require Significant Expenditures.

The exploration, development, production, gathering, processing, transportation and sale of oil and natural gas in the United States are subject to many federal, state and local laws, rules and regulations, including complex environmental laws and regulations. Matters subject to regulation include discharge permits, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, taxation, gathering and transportation of oil, natural gas and NGLs, environmental matters and health and safety criteria addressing worker protection. Under these laws and regulations, we may be required to make large expenditures that could materially adversely affect our financial condition, results of operations and cash flows. If existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations or those of our service providers, such changes may affect the costs that we pay for such services or the results of business. In addition to expenditures required in order for us to comply with such laws and regulations, expenditures required by such laws and regulations could also include payments for:

- personal injuries;
- property damage;
- containment and clean-up of oil, produced water and other spills;
- management and disposal of hazardous materials;
- remediation, clean-up costs and natural resource damages; and
- other environmental damages.

We do not believe that full insurance coverage for all potential damages is available at a reasonable cost. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, injunctive relief and/or the imposition of investigatory or other remedial obligations. The costs of remedying noncompliance may be significant, and remediation obligations could adversely affect our financial condition, results of operations and leasehold acreage. Laws, rules and regulations protecting the environment have changed frequently and the changes often include increasingly stringent requirements. These laws, rules and regulations may impose liability on us for environmental damage and disposal of hazardous and non-hazardous materials even if we were not negligent or at fault. We may also be found to be liable for the conduct of others or for acts that complied with applicable laws, rules or regulations at the time we performed those acts. These laws, rules and regulations are interpreted and enforced by numerous federal and state agencies. In addition, private parties, including the owners of properties upon which our wells are drilled or our facilities are located, the owners of properties adjacent to or in close proximity to those properties or non-governmental organizations such as environmental groups, may also pursue legal actions against us based on alleged non-compliance with certain of these laws, rules and regulations. For example, a number of lawsuits have been filed in some states alleging that fluid injection or oil and natural gas extraction have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal.

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact statements and/or plans of development before commencing exploration and production or midstream activities. Oil and natural gas operations in certain of our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Furthermore, we participate in candidate conservation agreements for the lesser prairie-chicken, the sand dune lizard and the Texas hornshell mussel, pursuant to which we are restricted from operating in certain sensitive locations or at certain times. Participation in such agreements or the designation of previously unprotected species as threatened or endangered species could prohibit drilling or other operations in certain of our operating areas, cause us to incur increased costs arising from species protection measures or result in limitations on our exploration and production and midstream activities, each of which could have an adverse impact on our business, financial condition, results of operations and cash flows. See “Business — Regulation.”

We Are Subject to Federal, State and Local Taxes, and May Become Subject to New Taxes or Have Eliminated or Reduced Certain Federal Income Tax Deductions Currently Available with Respect to Oil and Natural Gas Exploration and Production Activities as a Result of Future Legislation, Which Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and additional increases may occur. In addition, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals.

Periodically, legislation is introduced to eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for certain oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production or manufacturing activities and (iv) the increase in the amortization period for geological and geophysical costs paid or incurred in connection with the exploration for, or development of, oil or natural gas within the United States. The Tax Cuts and Jobs Act did not include any of these proposals, except for the repeal of the domestic manufacturing tax deduction for oil and natural gas companies. However, it is possible that such provisions could be proposed in the future. The passage of any legislation or any other similar change in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and natural gas exploration and production activities and could negatively impact our financial condition, results of operations and cash flows.

In January 2019, a bill was introduced in the New Mexico Senate to add a surtax on natural gas processors that would start at $0.60 per MMBtu in 2020 and escalate to $3.00 per MMBtu by 2024. Although the bill was not passed in 2019, any such surtax would adversely affect the ability of San Mateo and other natural gas processors to operate in New Mexico and would adversely affect the prices we receive for our natural gas processed in New Mexico.

The Tax Cuts and Jobs Act May Impact Our Ability to Fully Utilize Our Interest Expense Deductions and Net Operating Loss Carryovers to Fully Offset Our Taxable Income in Future Periods.

The Tax Cuts and Jobs Act includes provisions that generally (i) limit our annual deductions for interest expense to no more than 30% of our "adjusted taxable income" (plus 100% of our business interest income) for the year, (ii) permit us to offset only 80% (rather than 100%) of our taxable income with net operating losses we generate and (iii) limit our ability to deduct certain elements of executive compensation. Interest expense and net operating losses subject to these limitations may be carried forward by us for use in later years, subject to these limitations. Additionally, the Tax Cuts and Jobs Act repealed the domestic manufacturing tax deduction for oil and natural gas companies. These tax law changes could have the effect of causing us to incur income tax liability sooner than we otherwise would have incurred such liability or, in certain cases, could cause us to incur income tax liability that we might not have incurred otherwise, in the absence of these tax law changes.

Federal and State Legislation and Regulatory Initiatives Relating to Hydraulic Fracturing Could Result in Increased Costs and Additional Operating Restrictions or Delays.

Hydraulic fracturing involves the injection of water, sand or other proppants and chemicals under pressure into rock formations to stimulate oil and natural gas production. We routinely use hydraulic fracturing to complete wells in order to produce oil, natural gas and NGLs from formations such as the Wolfcamp and Bone Spring plays, the Eagle Ford shale and the Haynesville shale, where we focus our operations. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements. Federal, state and local laws or regulations targeting various aspects of the hydraulic fracturing process are being considered, or have been proposed or implemented. In past sessions, Congress has considered, but has not passed, legislation to amend the SDWA, to remove the SDWA's exemption granted to most hydraulic fracturing operations (other than operations using fluids containing diesel) and to require reporting and disclosure of chemicals used by oil and natural gas companies in the hydraulic fracturing process. Also at the federal level, in March 2015, the BLM issued final rules, including new requirements relating to public disclosure, wellbore integrity and handling of flowback water, to regulate hydraulic fracturing on federal and Indian lands. These rules were rescinded by rule in December 2017; however, in January 2018, California and a coalition of environmental groups filed a lawsuit in the Northern District of California to challenge the BLM's rescission of the rules. This litigation is ongoing and future implementation of the BLM rules is uncertain at this time.

Various policy makers, regulatory agencies and political candidates at the federal, state and local levels have proposed restrictions on hydraulic fracturing, including its outright prohibition. For example, certain candidates seeking the office of the President of the United States in 2020 have pledged to ban hydraulic fracturing. It is possible that any such restrictions on hydraulic fracturing may particularly target activity on federal lands, which could adversely impact our operations in the Delaware Basin. In addition, a number of states and local regulatory authorities are considering or have implemented more stringent regulatory requirements applicable to hydraulic fracturing, including bans or moratoria on drilling that effectively prohibit further production of oil and natural gas through the use of hydraulic fracturing or similar operations. For example, in December 2014, New York announced a moratorium on high volume fracturing activities combined with horizontal drilling following the issuance of a study regarding the safety of hydraulic fracturing. Certain communities in Colorado have also enacted bans on hydraulic fracturing. These actions are the subject of legal challenges. Texas and New Mexico have adopted regulations that require the disclosure of information regarding the substances used in the hydraulic fracturing process. In 2019 and 2020, separate bills were introduced in the New Mexico Senate to place a moratorium on hydraulic fracturing. Although such bills have not passed, similar laws, rules, regulations or orders at the local, state or federal level could limit our operations.

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

The Potential Adoption of Federal, State and Local Legislation and Regulations Intended to Address Potential Induced Seismicity in the Areas in Which We Operate Could Restrict Our Drilling and Production Activities, as well as Our Ability to Dispose of Produced Water Gathered from Such Activities, Which Could Decrease San Mateo's Revenues and Result in Increased Costs and Additional Operating Restrictions or Delays.

State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for produced water disposal and the increased occurrence of seismic activity. When caused by human activity, such events are called "induced seismicity." Regulatory agencies at all levels are continuing to study the possible link between oil and natural gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states alleging that fluid injection or oil and natural gas extraction have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise, to assess the relationship between seismicity and the use of such wells.

While the scientific community and regulatory agencies at all levels are continuing to study the possible link between oil and natural gas activity and induced seismicity, some state regulatory agencies, including in Texas and New Mexico, have modified their regulations or guidance to mitigate potential causes of induced seismicity.

Increased seismicity in areas in which we operate could result in additional regulation and restrictions on our operations and could lead to operational delays or increased operating costs. Additional regulation and attention given to induced seismicity could also lead to greater opposition, including litigation, to oil and natural gas activities. We and San Mateo dispose of large volumes of produced water gathered from our and third parties' drilling and production operations by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to dispose of produced water gathered from drilling and production activities could decrease San Mateo's revenues and result in increased costs and additional operating restrictions or delays.

Legislation or Regulations Restricting Emissions of Greenhouse Gases Could Result in Increased Operating Costs and Reduced Demand for the Oil, Natural Gas and NGLs We Produce, while the Physical Effects of Climate Change Could Disrupt Our Production and Cause Us to Incur Significant Costs in Preparing for or Responding to Those Effects.

We believe it is likely that scientific and political attention to issues concerning the extent, causes of and responsibility for climate change will continue, with the potential for further regulations and litigation that could affect our operations. Our operations result in greenhouse gas emissions. The EPA has published its final findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. There were attempts at comprehensive federal legislation establishing a cap and trade program, but that legislation did not pass. Further, various states have considered or adopted legislation that seeks to control or reduce emissions of greenhouse gases from a wide range of sources. Internationally, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement, which was signed by the United States in April 2016, requires countries to review and "represent a progression" in their intended nationally determined contributions, which set greenhouse gas emission reduction goals, every five years beginning in 2020. In November 2019, the Trump administration formally moved to exit the Paris Agreement, initiating the treaty-mandated one-year process at the end of which the United States can officially exit the agreement. In January 2019, New Mexico's governor signed an executive order declaring that New Mexico would support the goals of the Paris Agreement by joining the U.S. Climate Alliance, a bipartisan coalition of governors committed to reducing greenhouse gas emissions consistent with the goals of the Paris Agreement. The stated objective of the executive order is to achieve a statewide reduction in greenhouse gas emissions of at least 45% by 2030 as compared to 2005 levels. The executive order also requires New Mexico regulatory agencies to create an "enforceable regulatory framework" to ensure methane emission reductions. The EPA has also finalized regulations targeting new sources of methane emissions from the oil and natural gas industry. However, in June 2017, the EPA proposed a two-year stay of certain requirements under this rule and in August 2019 proposed to eliminate the methane emissions limitations under the rule. Any future international agreements, federal or state laws or implementing regulations that may be adopted to address greenhouse gas emissions could, and in all likelihood would, require us to incur increased operating costs, adversely affecting our profits, and could adversely affect demand for the oil and natural gas we produce, depressing the prices we receive for oil and natural gas.

In an interpretative guidance on climate change disclosures, the SEC indicated that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland and water availability and quality. If such effects were to occur, there is the potential for our exploration and production operations to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production, less efficient or non-routine operating practices necessitated by climate effects and increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by us or other midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. In addition, our hydraulic fracturing operations require large amounts of water. See "—If We Are Unable to Acquire Adequate Supplies of Water for Our Drilling and Hydraulic Fracturing Operations or Are Unable to Dispose of the Water We Use at a Reasonable Cost and Pursuant to Applicable Environmental Rules, Our Ability to Produce Oil and Natural Gas Commercially and in Commercial Quantities Could Be Impaired." Should climate change or other drought conditions occur, our ability to obtain water of a sufficient quality and quantity could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

The adoption of legislation or regulatory programs to reduce greenhouse gas emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Reduced demand for the oil and natural gas that we produce could also have the effect of lowering the value of our reserves. In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Additionally, the threat of climate change has resulted in increasing political risk in the United States as various policy makers, regulatory agencies and political candidates at the federal, state and local levels, including candidates seeking the office of the President of the United States in 2020, have proposed bans of new leases for production of minerals on federal properties and various restrictions on hydraulic fracturing, including its outright prohibition. Any such restrictions or prohibitions, if enacted, could have an adverse impact on our business, financial condition, results of operations and cash flows. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and natural gas companies in connection with their greenhouse gas emissions. Should we be targeted by any such litigation or investigations, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors. The ultimate impact of greenhouse gas emissions-related agreements, legislation and measures on our financial performance is highly uncertain because we are unable to predict, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and tradeoffs that inevitably occur in connection with such processes.

New Regulations on All Emissions from Our Operations Could Cause Us to Incur Significant Costs.

In recent years, the EPA issued final rules to subject oil and natural gas operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants programs under the CAA and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured oil and natural gas wells, compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules have required changes to our operations, including the installation of new equipment to control emissions. The EPA finalized a more stringent National Ambient Air Quality Standard (“NAAQS”) for ozone in October 2015. The EPA finished promulgating final area designations under the new standard in 2018, which, to the extent areas in which we operate have been classified as “non-attainment” areas, may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. To the extent regions reclassified as non-attainment areas under the lower ozone standard have begun implementing new, more stringent regulations, those regulations could also apply to our or our customers’ operations. Generally, it takes states several years to develop compliance plans for their non-attainment areas. In November 2016, the Department of the Interior issued final rules relating to the venting, flaring and leaking of natural gas by oil and natural gas producers who operate on federal and Indian lands. The rules limit routine flaring of natural gas, require the payment of royalties on avoidable natural gas losses and require plans or programs relating to natural gas capture and leak detection and repair. The BLM then finalized a revised rule in 2018 that scaled back the waste-prevention requirements of the 2016 rule. Environmental groups as well as California and New Mexico have sued in federal district court to challenge the legality of aspects of the revised rule, and the outcome of this litigation is currently uncertain. If not withdrawn or significantly revised, these rules are expected to result in an increase to our operating costs and changes in our operations. In addition, several states are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. As a result of this continued regulatory focus, future federal and state regulations of the oil and natural gas industry remain a possibility and could result in increased compliance costs for our operations.

We May Incur Significant Costs and Liabilities Resulting from Compliance with Pipeline Safety Regulations.

Our pipelines are subject to stringent and complex regulation related to pipeline safety and integrity management. For instance, the Department of Transportation, through PHMSA, has established a series of rules that require pipeline operators to develop and implement integrity management programs for hazardous liquid (including oil) pipeline segments that, in the event of a leak or rupture, could affect high-consequence areas. The Rustler Breaks Oil Pipeline System is subject to such rules. PHMSA also recently proposed rulemaking that would expand existing integrity management requirements to natural gas transmission and gathering lines in areas with medium population densities. Additional action by PHMSA with respect to pipeline integrity management requirements may occur in the future. At this time, we cannot predict the cost of such requirements, but they could be significant. Moreover, violations of pipeline safety regulations can result in the imposition of significant penalties.

Several states have also passed legislation or promulgated rules to address pipeline safety. Compliance with pipeline integrity laws and other pipeline safety regulations issued by state agencies such as the TRC and the New Mexico Oil Conservation Division could result in substantial expenditures for testing, repairs and replacement. Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with PHMSA or state requirements will not have a material adverse effect on our results of operations or financial position.

A Change in the Jurisdictional Characterization of Some of Our Assets by FERC or a Change in Policy by FERC May Result in Increased Regulation of Our Assets, Which May Cause Our Revenues to Decline and Operating Expenses to Increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC regulation. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. Similarly, intrastate crude oil pipeline facilities are exempt from regulation by FERC under the ICA. In December 2018, San Mateo placed into service the Rustler Breaks Oil Pipeline System, which is subject to FERC jurisdiction and includes crude oil gathering and transportation pipelines from origin points in Eddy County, New Mexico to an interconnect with Plains Pipeline, L.P. We believe the other crude oil pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as an intrastate facility not subject to FERC regulation. Whether a pipeline provides service in interstate commerce or intrastate commerce is highly fact dependent and determined on a case-by-case basis. A change in the jurisdictional characterization of our facilities by FERC, the courts or Congress, a change in policy by FERC or Congress or the expansion of our activities may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

The Rates of Our Regulated Assets are Subject to Review and Reporting by Federal Regulators, Which Could Adversely Affect Our Revenues.

The Rustler Breaks Oil Pipeline System transports crude oil in interstate commerce. FERC regulates the rates, terms and conditions of service on pipelines that transport crude oil in interstate commerce. If a party with an economic interest were to file either a complaint against our tariff rates or protest any proposed increases to our tariff rates, or FERC were to initiate an investigation of our rates, then our rates could be subject to detailed review. If any proposed rate increases were found by FERC to be in excess of just and reasonable levels, FERC could order us to reduce our rates and to refund the amount by which the rate increases were determined to be excessive, plus interest. If our existing rates were found by FERC to be in excess of just and reasonable levels, we could be ordered to refund the excess we collected for up to two years prior to the date of the filing of the complaint challenging the rates, and we could be ordered to reduce our rates prospectively. In addition, a state commission also could investigate our intrastate rates or our terms and conditions of service on its own initiative or at the urging of a shipper or other interested party. If a state commission found that our rates exceeded levels justified by our cost of service, the state commission could order us to reduce our rates. Any such reductions may result in lower revenues and cash flows.

In addition, FERC's ratemaking policies are subject to change and may impact the rates charged and revenues received on the Rustler Breaks Oil Pipeline System and any other natural gas or crude oil pipeline that is determined to be under the jurisdiction of FERC.

Should We Fail to Comply with All Applicable FERC-Administered Statutes, Rules, Regulations and Orders, We Could Be Subject to Substantial Penalties and Fines.

Under the Energy Policy Act, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to approximately $1.2 million per day for each violation and disgorgement of profits associated with any violation. This maximum penalty authority established by statute will continue to be adjusted periodically for inflation. While the nature of our gathering facilities is such that these facilities have not yet been regulated by FERC, the Rustler Breaks Oil Pipeline System does transport crude oil in interstate commerce and, therefore, is subject to FERC regulation. Laws, rules and regulations pertaining to those and other matters may be considered or adopted by FERC or Congress from time to time. Failure to comply with those laws, rules and regulations in the future could subject us to civil penalty liability.

The Derivatives Legislation Adopted by Congress Could Have an Adverse Impact on Our Ability to Hedge Risks Associated with Our Business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), among other things, established federal oversight and regulation of certain derivative products, including commodity hedges of the type we use. The Dodd-Frank Act requires the Commodity Futures Trading Commission ("CFTC") and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when, or if, this will be accomplished.

In 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in 2012. However, in 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. In 2016, the CFTC decided to re-propose, rather than finalize, certain regulations, including limitations on speculative futures and swap positions. The CFTC has not acted on the re-proposed position limit regulations. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. The Dodd-Frank Act could also result in additional regulatory requirements on our derivative arrangements, which could include new margin, reporting and clearing requirements. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future.

If these types of commodity hedges become unavailable or uneconomic, our commodity price risk could increase, which would increase the volatility of revenues and may decrease the amount of credit available to us. Any limitations or changes in our use of derivative arrangements could also materially affect our cash flows, which could adversely affect our ability to make capital expenditures.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

Any of these consequences could have a material adverse effect on our business, financial condition and results of operations.

We May Have Difficulty Managing Growth in Our Business, Which Could Have a Material Adverse Effect on Our Business, Financial Condition, Results of Operations and Cash Flows and Our Ability to Execute Our Business Plan in a Timely Fashion.

Because of our size, growth in accordance with our business plans, if achieved, will place a significant strain on our financial, technical, operational and management resources. As and when we expand our activities, including our midstream business, through San Mateo or otherwise, there will be additional demands on our financial, technical and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the inability to recruit and retain experienced managers, geoscientists, petroleum engineers, landmen, midstream professionals, attorneys and financial and accounting professionals, could have a material adverse effect on our business, financial condition, results of operations and cash flows and our ability to execute our business plan in a timely fashion.

Our Success Depends, to a Large Extent, on Our Ability to Retain Our Key Personnel, Including Our Chairman and Chief Executive Officer, Management and Technical Team, the Members of Our Board of Directors and Our Special Board Advisors, and the Loss of Any Key Personnel, Board Member or Special Board Advisor Could Disrupt Our Business Operations.

Investors in our common stock must rely upon the ability, expertise, judgment and discretion of our management and the success of our technical team in identifying, evaluating and developing prospects and reserves. Our performance and success are dependent to a large extent on the efforts and continued employment of our management and technical personnel, including our Chairman and Chief Executive Officer, Joseph Wm. Foran. We do not believe that they could be quickly replaced with personnel of equal experience and capabilities, and their successors may not be as effective. We have entered into employment agreements with Mr. Foran and other key personnel. However, these employment agreements do not ensure that these individuals will remain in our employment. If Mr. Foran or other key personnel resign or become unable to continue in their present roles and if they are not adequately replaced, our business operations could be adversely affected. With the exception of Mr. Foran, we do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We have an active Board of Directors that meets at least quarterly throughout the year and is closely involved in our business and the determination of our operational strategies. Members of our Board of Directors work closely with management to identify potential prospects, acquisitions and areas for further development. If any of our directors resign or become unable to continue in their present role, it may be difficult to find replacements with the same knowledge and experience and, as a result, our operations may be adversely affected.

In addition, our Board of Directors consults regularly with our special Board advisors regarding our business and the evaluation, exploration, engineering and development of our prospects and properties. Due to the knowledge and experience of our special advisors, they play a key role in our multi-disciplined approach to making decisions regarding prospects, acquisitions and development. If any of our special advisors resign or become unable to continue in their present role, our operations may be adversely affected.

A Cyber Incident Could Occur and Result in Information Theft, Data Corruption, Operational Disruption or Financial Loss.

The oil and natural gas industry is dependent on digital technologies to conduct certain exploration, development, production, gathering, processing and financial activities. We depend on digital technology to, among other things, estimate oil and natural gas reserves quantities, plan, execute and analyze drilling, completion, production, gathering, processing and disposal operations, process and record financial and operating data and communicate with employees, shareholders, royalty owners and other third-party industry participants. Industrial control systems, such as our supervisory control and data acquisition (SCADA) systems, control important processes and facilities that are critical to our operations. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure or we were subject to cyberspace breaches, phishing schemes or attacks, possible consequences include financial losses and the inability to engage in any of the aforementioned activities. Any such consequence could have a material adverse effect on our business.

While we have experienced certain phishing schemes and efforts to access our network, we have not experienced any material losses due to cyber incidents. However, we may suffer such losses in the future. If our systems for protecting against cyber incidents prove to be insufficient, we could be adversely affected by unauthorized access to proprietary information, which could lead to data corruption, communication interruption, exposure of our or third parties' confidential or proprietary information, operational disruptions or financial loss. As cyber threats continue to evolve, we may be required to expend additional resources to continue to modify and enhance our protective systems or to investigate and remediate any vulnerabilities.

We Operate in a Litigious Environment and May Be Involved in Legal Proceedings That Could Have an Adverse Effect on Our Results of Operations and Financial Condition.

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

RISKS RELATING TO OUR COMMON STOCK

The Price of Our Common Stock Has Fluctuated Substantially and May Fluctuate Substantially in the Future.

Our stock price has experienced volatility and could vary significantly as a result of a number of factors. In 2019, our stock price fluctuated between a high of $22.25 and a low of $12.16. In addition, the trading volume of our common stock may continue to fluctuate and cause significant price variations to occur. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. In addition, the stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

Factors that could affect our stock price or result in fluctuations in the market price or trading volume of our common stock include:

- our actual or anticipated operating and financial performance and drilling locations, including oil and natural gas reserves estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and cash flows, or those of companies that are perceived to be similar to us;
- changes in revenue, cash flows or earnings estimates or publication of reports by equity research analysts;
- speculation in the press or investment community;
- announcement or consummation of acquisitions, dispositions or joint ventures by us;
- public reaction to our operations or plans, press releases, announcements and filings with the SEC;
- the publication of research or reports by industry analysts regarding the Company, its competitors or our industry;
- sales of our common stock by the Company, directors, officers or other shareholders, or the perception that such sales may occur;
- general financial market conditions and oil and natural gas industry market conditions, including fluctuations in the price of oil, natural gas and NGLs;
- domestic or global health concerns, including the outbreak of contagious or pandemic diseases, such as the recent coronavirus;
- the realization of any of the risk factors presented in this Annual Report;
- the recruitment or departure of key personnel;
- commencement of, involvement in or unfavorable resolution of litigation;
- the success of our exploration and development operations, our midstream business (including San Mateo) and the marketing of any oil, natural gas and NGLs we produce;
- changes in market valuations of companies similar to ours; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

Conservation Measures and a Negative Shift in Market Perception towards the Oil and Natural Gas Industry Could Adversely Affect Demand for Oil and Natural Gas and Our Stock Price.

Certain segments of the investor community have recently expressed negative sentiment towards investing in the oil and natural gas industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and natural gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and natural gas sector based on social and environmental considerations. Furthermore, fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. Such developments could result in downward pressure on the stock prices of oil and natural gas companies, including ours.

Certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas projects. With the continued volatility in oil and natural gas prices, and the possibility that interest rates will rise in the near term, increasing the cost of borrowing, certain investors have emphasized capital efficiency and free cash flow from earnings as key drivers for energy companies, especially those primarily focused in the shale play arena. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results. Furthermore, if we are unable to achieve the desired level of capital efficiency or free cash flow within the timeframe expected by the market, our stock price may be adversely affected.

If We Fail to Maintain Effective Internal Control over Financial Reporting in the Future, Our Ability to Accurately Report Our Financial Results Could Be Adversely Affected.

As a public company with listed equity securities, we are required to comply with laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE. Complying with these statutes, regulations and requirements is difficult and costly and occupies a significant amount of time of our Board of Directors and management.

Pursuant to the Sarbanes-Oxley Act, we are required to maintain internal control over financial reporting. Our efforts to maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future and comply with the certification and reporting obligations under Sections 302 and 404 of the Sarbanes-Oxley Act. Our management does not expect that our internal controls and disclosure controls will prevent all possible error or all fraud. Any failure to maintain effective controls could result in material misstatements that are not prevented or detected and corrected on a timely basis, which could potentially subject us to sanction or investigation by the SEC, the NYSE or other regulatory authorities. Ineffective internal controls could also cause investors to lose confidence in our reported financial information and adversely affect our business and our stock price.

We Do Not Presently Intend to Pay Any Cash Dividends on or Repurchase Any Shares of Our Common Stock.

We do not presently intend to pay any cash dividends on or repurchase any shares of our common stock. Any payment of future dividends will be at the discretion of our Board of Directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applicable to the payment of dividends and other considerations that our Board of Directors deems relevant. Cash dividend payments in the future may only be made out of legally available funds and, if we experience substantial losses, such funds may not be available. In addition, certain covenants in our Credit Agreement, the San Mateo Credit Facility and the indenture governing our outstanding senior notes may limit our ability to pay dividends or repurchase shares of our common stock. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment, and there is no guarantee that the price of our common stock will exceed the price you paid.

Future Sales of Shares of Our Common Stock by Existing Shareholders and Future Offerings of Our Common Stock by Us Could Depress the Price of Our Common Stock.

The market price of our common stock could decline as a result of sales of a large number of shares of our common stock in the market, including shares of equity or debt securities convertible into common stock, and the perception that these sales could occur may also depress the market price of our common stock. If our existing shareholders, including directors or officers, sell, or indicate an intent to sell, substantial amounts of our common stock in the public market, the trading price of our common stock could decline significantly. Sales of our common stock may make it more difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate. These sales could also cause our stock price to decrease and make it more difficult for you to sell shares of our common stock.

We may also sell or issue additional shares of common stock or equity or debt securities convertible into common stock in public or private offerings or in connection with acquisitions. We cannot predict the size of future issuances of our common stock or convertible securities or the effect, if any, that future issuances and sales of shares of our common stock or convertible securities would have on the market price of our common stock.

Provisions of Our Certificate of Formation, Bylaws and Texas Law May Have Anti-Takeover Effects That Could Prevent a Change in Control Even if It Might Be Beneficial to Our Shareholders.

Our certificate of formation and bylaws contain certain provisions that may discourage, delay or prevent a merger or acquisition that our shareholders may consider favorable. These provisions include:

- authorization for our Board of Directors to issue preferred stock without shareholder approval;
- a classified Board of Directors so that not all members of our Board of Directors are elected at one time;
- the prohibition of cumulative voting in the election of directors; and
- a limitation on the ability of shareholders to call special meetings to those owning at least 25% of our outstanding shares of common stock.

Provisions of Texas law may also discourage, delay or prevent someone from acquiring or merging with us, which may cause the market price of our common stock to decline. Under Texas law, a shareholder who beneficially owns more than 20% of our voting stock, or an affiliated shareholder, cannot acquire us for a period of three years from the date this person became an affiliated shareholder, unless various conditions are met, such as approval of the transaction by our Board of Directors before this person became an affiliated shareholder or approval of the holders of at least two-thirds of our outstanding voting shares not beneficially owned by the affiliated shareholder.

Our Directors and Executive Officers Own a Significant Percentage of Our Equity, Which Could Give Them Influence in Corporate Transactions and Other Matters, and the Interests of Our Directors and Executive Officers Could Differ from Other Shareholders.

As of February 28, 2020, our directors and executive officers beneficially owned approximately 7% of our outstanding common stock. These shareholders could influence or control to some degree the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of any amendment to our certificate of formation or bylaws and the approval of mergers and other significant corporate transactions. Their influence or control of the Company may have the effect of delaying or preventing a change of control of the Company and may adversely affect the voting and other rights of other shareholders. In addition, due to their ownership interest in our common stock, our directors and executive officers may be able to remain entrenched in their positions.

Our Board of Directors Can Authorize the Issuance of Preferred Stock, Which Could Diminish the Rights of Holders of Our Common Stock and Make a Change of Control of the Company More Difficult Even if It Might Benefit Our Shareholders.

Our Board of Directors is authorized to issue shares of preferred stock in one or more series and to fix the voting powers, preferences and other rights and limitations of the preferred stock. Accordingly, we may issue shares of preferred stock with a preference over our common stock with respect to dividends or distributions on liquidation or dissolution, or that may otherwise adversely affect the voting or other rights of the holders of common stock.

Issuances of preferred stock, depending upon the rights, preferences and designations of the preferred stock, may have the effect of delaying, deterring or preventing a change of control of the Company, even if that change of control might benefit our shareholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

Not applicable.

ITEM 2. PROPERTIES.

See "Business" for descriptions of our properties. We also have various operating leases for rental of office space and office and field equipment. See Note 4 to the consolidated financial statements in this Annual Report for the future minimum rental payments. Such information is incorporated herein by reference.

ITEM 3. LEGAL PROCEEDINGS.

We are party to several legal proceedings encountered in the ordinary course of business. While the ultimate outcome and impact on us cannot be predicted with certainty, in the opinion of management, it is remote that these legal proceedings will have a material adverse impact on our financial condition, results of operations or cash flows.

On November 4, 2019, the Company received a Notice of Violation and Finding of Violation from the EPA and a Notice of Violation from the New Mexico Environment Department (the "NMED") alleging violations of the CAA and New Mexico State Implementation Plan at certain of its operated locations in New Mexico. The Company has provided information to the EPA and NMED and is engaged in discussions regarding a resolution of the alleged violations. The Company believes it is remote that the resolution of this matter will have a material adverse impact on the Company's financial condition, results of operations or cash flows. Resolution of the matter may result in monetary sanctions of more than $100,000.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

GENERAL MARKET INFORMATION

Shares of our common stock are traded on the NYSE under the symbol "MTDR." Our shares have been traded on the NYSE since February 2, 2012. Prior to trading on the NYSE, there was no established public trading market for our common stock.

On February 28, 2020, we had 116,569,389 shares of common stock outstanding held by approximately 360 record holders, excluding shareholders for whom shares are held in "nominee" or "street" name.

EQUITY COMPENSATION PLAN INFORMATION

The following table presents the securities authorized for issuance under our equity compensation plans as of December 31, 2019.

	Equity Compensation Plan Information		
Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Shares Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders (1) (2)	3,956,574	$22.64	2,801,761
Equity compensation plans not approved by security holders	—	—	—
Total	3,956,574	$22.64	2,801,761

(1) Our Board of Directors has determined not to make any additional grants of awards under the Matador Resources Company 2003 Stock and Incentive Plan (the "2003 Plan") or the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan (the "2012 Incentive Plan").

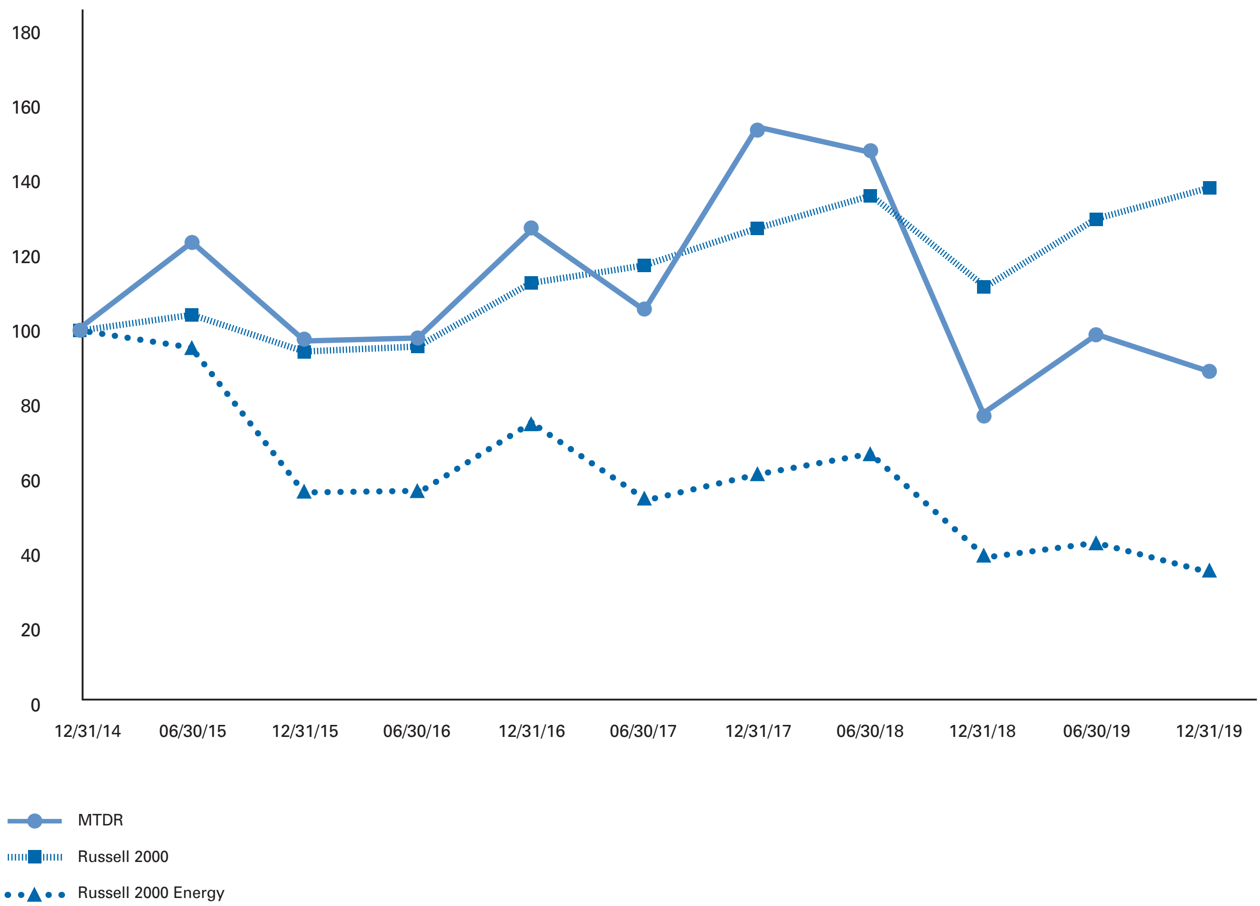
(2) The Matador Resources Company 2019 Long-Term Incentive Plan (the "2019 Incentive Plan") was adopted by our Board of Directors in April 2019 and approved by our shareholders on June 6, 2019. For a description of our 2019 Incentive Plan, see Note 9 to the consolidated financial statements in this Annual Report.

SHARE PERFORMANCE GRAPH

The following graph compares the cumulative return on a $100 investment in our common stock from December 31, 2014 through December 31, 2019, to that of the cumulative return on a $100 investment in the Russell 2000 Index and the Russell 2000 Energy Index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed.

This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing. This graph is included in accordance with the SEC's disclosure rules. This historic stock performance is not indicative of future stock performance.

COMPARISON OF CUMULATIVE TOTAL RETURN AMONG MATADOR RESOURCES COMPANY, THE RUSSELL 2000 INDEX AND THE RUSSELL 2000 ENERGY INDEX



REPURCHASE OF EQUITY BY THE COMPANY OR AFFILIATES

During the quarter ended December 31, 2019, the Company re-acquired shares of common stock from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted stock.

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased under the Plans or Programs
October 1, 2019 to October 31, 2019	163	$99.519		
— —				
November 1, 2019 to November 30, 2019	784	14.18	—	—
December 1, 2019 to December 31, 2019	—	—	—	—
Total	947	$14.09	—	—

(1) The shares were not re-acquired pursuant to any repurchase plan or program. The Company re-acquired shares of common stock from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted stock.

ITEM 6. SELECTED FINANCIAL DATA.

The following selected financial information is summarized from our results of operations for the five-year period ended December 31, 2019 and selected consolidated balance sheet and cash flow data at December 31, 2019, 2018, 2017, 2016 and 2015. You should read the following selected financial data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes thereto included elsewhere in this Annual Report. The financial information included in this Annual Report may not be indicative of our future results of operations, financial condition or cash flows.

	Year Ended December 31,				
	2019	2018	2017	2016	2015
(In thousands, except per share data)					
Statement of operations data:					
Revenues					
Oil and natural gas revenues	$892,325	$800,700	$528,684	$ 291,156	$ 278,340
Third-party midstream services revenues	59,110	21,920	10,198	5,218	1,864
Sales of purchased natural gas	74,769	7,071	—	—	—
Lease bonus - mineral acreage	1,711	2,489	—	—	—
Realized gain (loss) on derivatives	9,482	2,334	(4,321)	9,286	77,094
Unrealized (loss) gain on derivatives	(53,727)	65,085	9,715	(41,238)	(39,265)
Total revenues	983,670	899,599	544,276	264,422	318,033
Expenses					
Production taxes, transportation and processing	92,273	76,138	58,275	43,046	35,650
Lease operating	117,305	92,966	67,313	56,202	54,704
Plant and other midstream services operating	36,798	24,609	13,039	5,389	3,489
Purchased natural gas	69,398	6,635	—	—	—
Depletion, depreciation and amortization	350,540	265,142	177,502	122,048	178,847
Accretion of asset retirement obligations	1,822	1,530	1,290	1,182	734
Full-cost ceiling impairment	—	—	—	158,633	801,166
General and administrative	80,054	69,308	66,016	55,089	50,105
Total expenses	748,190	536,328	383,435	441,589	1,124,695
Operating income (loss)	235,480	363,271	160,841	(177,167)	(806,662)
Other income (expense)					
Net (loss) gain on asset sales and inventory impairment	(967)	(196)	23	107,277	908
Interest expense	(73,873)	(41,327)	(34,565)	(28,199)	(21,754)
Prepayment premium on extinguishment of debt	—	(31,226)	—	—	—
Other (expense) income	(2,126)	1,551	3,551	(4)	616
Total other (expense) income	(76,966)	(71,198)	(30,991)	79,074	(20,230)
Income (loss) before income taxes	158,514	292,073	129,850	(98,093)	(826,892)
Income tax provision (benefit)					
Current	—	(455)	(8,157)	(1,036)	2,959
Deferred	35,532	(7,236)	—	—	(150,327)
Total income tax provision (benefit)	35,532	(7,691)	(8,157)	(1,036)	(147,368)
Net income (loss)	122,982	299,764	138,007	(97,057)	(679,524)
Net income attributable to non-controlling interest in subsidiaries	(35,205)	(25,557)	(12,140)	(364)	(261)
Net income (loss) attributable to Matador Resources Company shareholders	$ 87,777	$ 274,207	$125,867	$ (97,421)	$ (679,785)
Earnings (loss) per common share					
Basic	$ 0.75	$ 2.41	$ 1.23	$ (1.07)	$ (8.34)
Diluted	$ 0.75	$ 2.41	$ 1.23	$ (1.07)	$ (8.34)

	At December 31,				
	2019	2018	2017	2016	2015
(In thousands)					
Balance sheet data:					
Cash and cash equivalents	$ 40,024	$ 64,545	$ 96,505	$ 212,884	$ 16,732
Restricted cash	$ 25,104	$ 19,439	$ 5,977	$ 1,258	$ 44,357
Net property and equipment	$3,699,595	$3,122,864	$1,881,456	$1,184,525	$1,012,406
Total assets	$4,069,676	$3,455,518	$2,145,690	$1,464,665	$1,140,861
Current liabilities	$ 399,772	$ 330,022	$ 282,606	$ 169,505	$ 136,830
Long-term liabilities	$1,700,452	$1,345,839	$ 605,538	$ 603,715	$ 515,072
Total Matador Resources Company shareholders' equity	$1,833,654	$1,688,880	$1,156,556	$ 690,125	$ 488,003

	Year Ended December 31,				
	2019	2018	2017	2016	2015
(In thousands)					
Other financial data:					
Net cash provided by operating activities	$ 552,042	$ 608,523	$ 299,125	$ 134,086	$ 208,535
Net cash used in investing activities	$ (903,976)	$(1,515,253)	$ (819,284)	$ (448,739)	$ (381,406)
Oil and natural gas properties capital expenditures	$ (730,161)	$(1,357,802)	$ (699,445)	$ (379,067)	$ (432,715)
Midstream capital expenditures	$ (192,035)	$ (163,222)	$ (115,128)	$ (74,845)	$ (64,499)
Net cash provided by financing activities	$ 333,078	$ 888,232	$ 408,499	$ 467,706	$ 224,944
Adjusted EBITDA attributable to Matador Resources Company shareholders [(1)]	$ 610,756	$ 553,223	$ 336,063	$ 157,892	$ 223,138

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "—Non-GAAP Financial Measures" below.

NON-GAAP FINANCIAL MEASURES

We define Adjusted EBITDA attributable to Matador shareholders ("Adjusted EBITDA") as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, prepayment premium on extinguishment of debt and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss) or net cash provided by operating activities as determined in accordance with GAAP or as a primary indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

The following table presents our calculation of Adjusted EBITDA, on a consolidated basis, and the reconciliation of such Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

	Year Ended December 31,				
	2019	2018	2017	2016	2015
(In thousands)					
Unaudited Adjusted EBITDA Reconciliation to Net Income (Loss):					
Net income (loss) attributable to Matador Resources Company shareholders	$ 87,777	$274,207	$125,867	$ (97,421)	$(679,785)
Net income attributable to non-controlling interest in subsidiaries	35,205	25,557	12,140	364	261
Net income (loss)	122,982	299,764	138,007	(97,057)	(679,524)
Interest expense	73,873	41,327	34,565	28,199	21,754
Total income tax provision (benefit)	35,532	(7,691)	(8,157)	(1,036)	(147,368)
Depletion, depreciation and amortization	350,540	265,142	177,502	122,048	178,847
Accretion of asset retirement obligations	1,822	1,530	1,290	1,182	734
Full-cost ceiling impairment	—	—	—	158,633	801,166
Unrealized loss (gain) on derivatives	53,727	(65,085)	(9,715)	41,238	39,265
Stock-based compensation expense	18,505	17,200	16,654	12,362	9,450
Net loss (gain) on asset sales and inventory impairment	967	196	(23)	(107,277)	(908)
Prepayment premium on extinguishment of debt	—	31,226	—	—	—
Consolidated Adjusted EBITDA	657,948	583,609	350,123	158,292	223,416
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(47,192)	(30,386)	(14,060)	(400)	(278)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$610,756	$553,223	$336,063	$ 157,892	$ 223,138

	Year Ended December 31,				
	2019	2018	2017	2016	2015
(In thousands)					
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:					
Net cash provided by operating activities	$552,042	$608,523	$299,125	$134,086	$208,535
Net change in operating assets and liabilities	34,517	(64,429)	25,058	(1,809)	(8,980)
Interest expense, net of non-cash portion	71,389	39,970	34,097	27,051	20,902
Current income tax (benefit) provision	—	(455)	(8,157)	(1,036)	2,959
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(47,192)	(30,386)	(14,060)	(400)	(278)
Adjusted EBITDA attributable to Matador Resources Company shareholders	610,756	553,223	336,063	157,892	223,138

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in oil or natural gas prices, the timing of planned capital expenditures, availability under our Credit Agreement and the San Mateo Credit Facility, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting our oil and natural gas and midstream operations, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of gathering, processing and transportation facilities, availability and integration of acquisitions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Note Regarding Forward-Looking Statements."

For a comparison of our results of operations for the years ended December 31, 2018 and December 31, 2017, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2018, filed with the SEC on March 1, 2019.

OVERVIEW

We are an independent energy company founded in July 2003 engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana. Additionally, we conduct midstream operations, primarily through San Mateo, in support of our exploration, development and production operations and provide natural gas processing, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties.

2019 Operational Highlights

During the year ended December 31, 2019, we completed and began producing oil and natural gas from 76 gross (61.4 net) operated and 62 gross (4.3 net) non-operated wells in the Delaware Basin and from eight gross (7.9 net) operated wells in South Texas. We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana during 2019, although we did participate in the drilling and completion of 26 gross (1.7 net) non-operated Haynesville shale wells that began producing in 2019.

During 2019, we continued our focus on the exploration, delineation and development of our Delaware Basin acreage in Loving County, Texas and Lea and Eddy Counties, New Mexico. We operated six drilling rigs in the Delaware Basin throughout 2019. In October 2018, we commenced a drilling program in South Texas to drill nine wells, primarily in the Eagle Ford shale, to take advantage of higher oil and natural gas prices in South Texas, to conduct at least one exploratory test of the Austin Chalk formation and to validate and hold by production almost all of our remaining undeveloped acreage in South Texas. One of the Eagle Ford shale wells was completed and turned to sales during the fourth quarter of 2018, and the remaining eight wells, including one well drilled in the Austin Chalk formation, were completed and turned to sales in the first half of 2019.

The vast majority of our 2019 capital expenditures was directed to (i) the delineation and development of our leasehold position in the Delaware Basin, (ii) the development of certain midstream assets to support our operations there, (iii) our participation in non-operated wells drilled and completed in the Delaware Basin and (iv) the acquisition of additional leasehold and mineral interests prospective for the Wolfcamp, Bone Spring and other liquids-rich plays in the Delaware Basin. Our remaining capital expenditures were primarily directed to our short-term drilling and completion program in South Texas and to our participation in several non-operated wells drilled and completed in the Haynesville shale throughout 2019.

Our average daily oil equivalent production for the year ended December 31, 2019 was 66,203 BOE per day, including 38,312 Bbl of oil per day and 167.4 MMcf of natural gas per day, an increase of 27%, as compared to 52,128 BOE per day, including 30,524 Bbl of oil per day and 129.6 MMcf of natural gas per day, for the year ended December 31, 2018. Our average daily oil production in 2019 of 38,312 Bbl of oil per day increased 26% from 30,524 Bbl of oil per day in 2018. This increase in oil production was primarily a result of our ongoing delineation and development drilling activities in the Delaware Basin as well as from our nine-well program in South Texas concluded in the first half of 2019. Our average daily natural gas production of 167.4 MMcf per day in 2019 increased 29% from 129.6 MMcf per day in 2018. This increase in natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin as well as from non-operated Haynesville shale wells completed and turned to sales during the third quarter of 2019. Oil production comprised 58% of our total production for the year ended December 31, 2019, as compared to 59% for the year ended December 31, 2018.

For the year ended December 31, 2019, our oil and natural gas revenues were $892.3 million, an increase of 11% from oil and natural gas revenues of $800.7 million for the year ended December 31, 2018. Our oil revenues increased 20% to approximately $759.8 million, as compared to $635.6 million for the year ended December 31, 2018. The increase in oil revenues resulted from the increase in oil production for the year ended December 31, 2019 noted above, partially offset by a lower weighted average realized oil price of $54.34 per Bbl in 2019, as compared to $57.04 per Bbl in 2018. Our natural gas revenues decreased 20% to approximately $132.5 million, as compared to $165.1 million for the year ended December 31, 2018. The decrease in natural gas revenues resulted from a lower weighted average realized natural gas price of $2.17 per Mcf in 2019, as compared to $3.49 per Mcf in 2018. This decrease was partially offset by the increase in our natural gas production noted above.

We reported net income attributable to Matador shareholders of approximately $87.8 million, or $0.75 per diluted common share, on a GAAP basis for the year ended December 31, 2019, as compared to net income of $274.2 million, or $2.41 per diluted common share, for the year ended December 31, 2018. Adjusted EBITDA for the year ended December 31, 2019 was $610.8 million, as compared to Adjusted EBITDA of $553.2 million for the year ended December 31, 2018. Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "Selected Financial Data — Non-GAAP Financial Measures."

At December 31, 2019, our estimated total proved oil and natural gas reserves were 252.5 million BOE, including 148.0 million Bbl of oil and 627.2 Bcf of natural gas, with a Standardized Measure of $2.03 billion and a PV-10 of $2.25 billion. At December 31, 2018, our estimated total proved oil and natural gas reserves were 215.3 million BOE, including 123.4 million Bbl of oil and 551.5 Bcf of natural gas, with a Standardized Measure of $2.25 billion and a PV-10 of $2.58 billion. Our estimated total proved reserves of 252.5 million BOE at December 31, 2019 represented a 17% year-over-year increase, as compared to 215.3 million BOE at December 31, 2018. Our estimated proved oil reserves of 148.0 million Bbl at December 31, 2019 increased 20%, as compared to 123.4 million Bbl at December 31, 2018. Our proved oil and natural gas reserves in the Delaware Basin increased 22% to 232.8 million BOE at December 31, 2019, as compared to 191.5 million BOE at December 31, 2018, primarily as a result of our ongoing delineation and development operations there. At December 31, 2019, approximately 92% of our total proved oil and natural gas reserves were attributable to our properties in the Delaware Basin. Our proved oil reserves in the Delaware Basin increased 22% to 139.6 million Bbl at December 31, 2019, as compared to 114.8 million Bbl at December 31, 2018. Proved oil reserves comprised 59% of our total proved reserves at December 31, 2019, as compared to 57% at December 31, 2018. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "Business — Estimated Proved Reserves."

Midstream Highlights

On February 25, 2019, we announced the formation of San Mateo II, a strategic joint venture with a subsidiary of Five Point designed to expand our midstream operations in the Delaware Basin, specifically in Eddy County, New Mexico. San Mateo II is owned 51% by us and 49% by Five Point. As part of this transaction, we dedicated to San Mateo II acreage in the Greater Stebbins Area and the Stateline asset area pursuant to 15-year, fixed-fee agreements for oil, natural gas and salt water gathering, natural gas processing and salt water disposal. In addition, Five Point has committed to pay $125.0 million of the first $150.0 million of capital expenditures incurred by San Mateo II to develop facilities in the Greater Stebbins Area and the Stateline asset area. Five Point has also provided us the opportunity to earn deferred performance incentives of up to $150.0 million over the next several years as we execute our operational plans in and around the Greater Stebbins Area and the Stateline asset area, plus additional performance incentives for securing volumes from third-party customers.

San Mateo achieved strong operating results in 2019, highlighted by (i) increased third-party midstream services revenues, (ii) increased natural gas gathering and processing volumes, (iii) increased water gathering and water disposal volumes and (iv) increased oil gathering volumes, all as compared to 2018. San Mateo initiated construction on an additional 200 MMcf per day of designed natural gas processing inlet capacity as part of the expansion of the Black River Processing Plant, which is anticipated to be placed in service during the summer of 2020 and would bring the total designed inlet capacity of the Black River Processing Plant to 460 MMcf of natural gas per day. San Mateo also initiated plans to construct large diameter natural gas gathering lines southward from the Greater Stebbins Area and northward from the Stateline asset area to connect these areas with the Black River Processing Plant. During 2019, San Mateo added four commercial salt water disposal wells, two in the Rustler Breaks asset area and two in the Greater Stebbins Area, and expects to place into service one additional commercial salt water disposal well in the Rustler Breaks asset area late in the first quarter of 2020, bringing San Mateo's designed salt water disposal capacity to approximately 335,000 Bbl per day.

During 2019, San Mateo received an increased natural gas gathering and processing commitment from an existing natural gas customer, plus other interruptible volumes, obtained significant additional acreage dedications from existing salt water customers and added an acreage dedication from a new oil customer. At certain times near the end of the third quarter and in the fourth quarter of 2019, as a result of increased throughput from existing natural gas processing customers, San Mateo was operating the Black River Processing Plant at greater than 95% of the current designed inlet capacity of 260 MMcf per day.

2020 Capital Expenditure Budget

We expect that development of our Delaware Basin assets will be the primary focus of our operations and capital expenditures in 2020. We plan to operate six contracted drilling rigs drilling primarily oil and natural gas wells in the Delaware Basin throughout 2020. Our 2020 estimated capital expenditure budget consists of $690.0 to $750.0 million for drilling, completing and equipping wells ("D/C/E capital expenditures") and $85.0 to $105.0 million for midstream capital expenditures, which primarily reflects our proportionate share of San Mateo's estimated combined 2020 capital expenditures of $190.0 to $235.0 million and also accounts for the remaining portions of the $50.0 million capital carry that Five Point agreed to provide to us in conjunction with the formation of San Mateo II. Substantially all of these 2020 estimated capital expenditures will be allocated to (i) the further delineation and development of our leasehold position, (ii) the continued construction of midstream assets and (iii) our participation in certain non-operated well opportunities in the Delaware Basin, with the exception of amounts allocated to limited operations in our South Texas and Haynesville shale positions to maintain and extend leases and to participate in certain non-operated well opportunities. Our 2020 Delaware Basin drilling program is expected to focus on the continued development of our various asset areas throughout the Delaware Basin, with a particular emphasis on drilling and completing a higher percentage of longer horizontal wells in 2020, including 74% with anticipated completed lateral lengths of two miles.

To narrow any potential difference between our 2020 capital expenditures and operating cash flows, we may divest portions of our non-core assets, particularly in the Haynesville shale and in our South Texas position (as we did in 2019), as well as consider monetizing other assets, such as certain mineral, royalty and midstream interests, as value-creating opportunities arise. In addition, we intend to continue evaluating the opportunistic acquisition of acreage and mineral interests, principally in the Delaware Basin, during 2020. These monetizations, divestitures and expenditures are opportunity-specific, and purchase price multiples and per-acre prices can vary significantly based on the asset or prospect. As a result, it is difficult to estimate these 2020 monetizations, divestitures and capital expenditures with any degree of certainty; therefore, we have not provided estimated proceeds related to monetizations or divestitures or estimated capital expenditures related to acreage and mineral acquisitions for 2020.

At December 31, 2019, we had $40.0 million in cash (excluding restricted cash) and $198.9 million in undrawn borrowing capacity under our Credit Agreement (after giving effect to outstanding letters of credit based upon our elected borrowing commitment of $500.0 million). The Credit Agreement was amended in February 2020 to increase our elected borrowing commitment from $500.0 million to $700.0 million, which increased our undrawn borrowing capacity to $399.0 million (after giving effect to then-outstanding letters of credit). Excluding any possible significant acquisitions, we expect to fund our 2020 capital expenditures through a combination of cash on hand, operating cash flows, performance incentives in connection with San Mateo, borrowings under our Credit Agreement (assuming availability under our borrowing base of $900.0 million) and borrowings under the San Mateo Credit Facility (assuming availability under the accordion feature of such facility to up to $400.0 million). In addition, in 2020, we expect to receive a portion of the $50.0 million capital carry Five Point agreed to provide to us in conjunction with the formation of San Mateo II. We continually evaluate other capital sources, including borrowings under additional credit arrangements, the sale or joint venture of midstream assets, oil and natural gas producing assets, leasehold interests or mineral interests and potential issuances of equity, debt or convertible securities, none of which may be available on satisfactory terms or at all. The aggregate amount of capital we expend may fluctuate materially based on market conditions, the actual costs to drill, complete and place on production operated or non-operated wells, our drilling results, the actual costs and scope of our midstream activities, the ability of our joint venture partners to meet their capital obligations, other opportunities that may become available to us and our ability to obtain capital.

REVENUES

Our revenues are derived primarily from the sale of oil, natural gas and NGL production. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in oil, natural gas or NGL prices.

The following table summarizes our revenues and production data for the periods indicated.

	Year Ended December 31,		
	2019	2018	2017
Operating Data:			
Revenues (in thousands): (1)			
Oil	$759,811	$635,554	$386,865
Natural gas	132,514	165,146	141,819
Total oil and natural gas revenues	892,325	800,700	528,684
Third-party midstream services revenues	59,110	21,920	10,198
Sales of purchased natural gas	74,769	7,071	—
Lease bonus - mineral acreage	1,711	2,489	—
Realized gain (loss) on derivatives	9,482	2,334	(4,321)
Unrealized (loss) gain on derivatives	(53,727)	65,085	9,715
Total revenues	$983,670	$899,599	$544,276
Net Production Volumes: (1)			
Oil (MBbl)	13,984	11,141	7,851
Natural gas (Bcf)	61.1	47.3	38.2
Total oil equivalent (MBOE) (2)	24,164	19,026	14,212
Average daily production (BOE/d) (2)	66,203	52,128	38,936
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$ 54.34	$ 57.04	$ 49.28
Oil, with realized derivatives (per Bbl)	$ 54.98	$ 57.38	$ 48.81
Natural gas, without realized derivatives (per Mcf)	$ 2.17	$ 3.49	$ 3.72
Natural gas, with realized derivatives (per Mcf)	$ 2.18	$ 3.46	$ 3.70

(1) We report our production volumes in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Revenues associated with NGLs are included with our natural gas revenues.

(2) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Year Ended December 31, 2019 as Compared to Year Ended December 31, 2018

Oil and natural gas revenues. Our oil and natural gas revenues increased $91.6 million, or 11%, to $892.3 million for the year ended December 31, 2019, as compared to $800.7 million for the year ended December 31, 2018. Our oil revenues increased $124.3 million, or 20%, to $759.8 million for the year ended December 31, 2019, as compared to $635.6 million for the year ended December 31, 2018. This increase in our oil revenues resulted primarily from the 26% increase in our oil production to 14.0 million Bbl of oil for the year ended December 31, 2019, as compared to 11.1 million Bbl of oil for the year ended December 31, 2018. The increase in oil production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin, as well as our nine-well program in the Eagle Ford shale play concluded in the first half of 2019. This increase was partially offset by a 5% decrease in the weighted average oil price realized for the year ended December 31, 2019 to $54.34 per Bbl, as compared to $57.04 per Bbl realized for the year ended December 31, 2018. Our natural gas revenues decreased by $32.6 million, or 20%, to $132.5 million for the year ended December 31, 2019, as compared to $165.1 million for the year ended December 31, 2018. The decrease in natural gas revenues resulted primarily from a 38% decrease in realized natural gas prices to $2.17 per Mcf for the year ended December 31, 2019, as compared to $3.49 per Mcf realized for the year ended December 31, 2018. This decrease was partially offset by the 29% increase in our natural gas production to 61.1 Bcf for the year ended December 31, 2019, as compared to 47.3 Bcf for the year ended December 31, 2018. The increase in natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin as well as from non-operated Haynesville shale wells completed and turned to sales during the year ended December 31, 2019.

Third-party midstream services revenues. Our third-party midstream services revenues increased $37.2 million, or 170%, to $59.1 million for the year ended December 31, 2019, as compared to $21.9 million for the year ended December 31, 2018. Third-party midstream services revenues are those revenues from midstream operations related to third parties, including working interest owners in our operated wells. This increase was primarily attributable to (i) an increase in our third-party natural gas gathering, transportation and processing revenues to approximately $27.0 million for the year ended December 31, 2019, as compared to $10.7 million for the year ended December 31, 2018, (ii) an increase in third-party salt water gathering and disposal revenues to approximately $24.9 million for the year ended December 31, 2019, as compared to approximately $10.5 million for the year ended December 31, 2018, and (iii) an increase in our third-party oil transportation revenues to approximately $7.2 million for the year ended December 31, 2019, as compared to $0.7 million for the year ended December 31, 2018.

Sales of purchased natural gas. Our sales of purchased natural gas were $74.8 million for the year ended December 31, 2019, as compared to $7.1 million for the year ended December 31, 2018. Sales of purchased natural gas primarily reflect those natural gas purchase transactions that we periodically enter into with third parties whereby we purchase natural gas, process the natural gas at the Black River Processing Plant and subsequently sell the residue gas and NGLs to other purchasers. These revenues, and the expenses related to these transactions included in "Purchased natural gas," are presented on a gross basis in our consolidated statement of operations.

Lease bonus - mineral acreage. Our lease bonus - mineral acreage revenues were $1.7 million for the year ended December 31, 2019, as compared to $2.5 million for the year ended December 31, 2018. Lease bonus - mineral acreage revenues reflect the payments we receive to enter into or extend leases to third-party lessees to develop the oil and natural gas attributable to certain of our mineral interests.

Realized gain on derivatives. Our realized net gain on derivatives was $9.5 million for the year ended December 31, 2019, as compared to a realized net gain of approximately $2.3 million for the year ended December 31, 2018. We realized a net gain of $8.9 million and $0.5 million from our oil and natural gas costless collar contracts, respectively, for the year ended December 31, 2019, resulting from oil and natural gas prices that were below the floor prices of certain of our oil and natural gas costless collar contracts. We realized a net gain of $0.1 million from our oil basis swap contracts for the year ended December 31, 2019, resulting from oil basis prices that were lower than the swap prices on certain of our oil basis swap contracts. We realized a net gain of $29.5 million from our oil basis swap contracts for the year ended December 31, 2018, resulting from oil basis prices that were lower than the swap prices on certain of our oil basis swap contracts. This net gain was significantly offset by net losses of $25.7 million and $1.4 million from our oil and natural gas costless collar contracts, respectively, for the year ended December 31, 2018, resulting from oil and natural gas prices that were above the short call/ceiling prices of certain of our oil and natural gas costless collar contracts. We realized an average gain on our oil derivatives of approximately $0.64 per Bbl of oil produced during the year ended December 31, 2019, as compared to an average gain of $0.34 per Bbl of oil produced during the year ended December 31, 2018. Our total oil volumes hedged for the year ended December 31, 2019 represented 59% of our total oil production, as compared to 49% of our total oil production for the year ended December 31, 2018. We realized an average gain on our natural gas derivatives of approximately $0.01 per Mcf produced during the year ended December 31, 2019, as compared to an average loss of approximately $0.03 per Mcf produced for the year ended December 31, 2018. Our total natural gas volumes hedged for the year ended December 31, 2019 represented 12% of our total natural gas production, as compared to 36% of our total natural gas production for the year ended December 31, 2018.

Unrealized (loss) gain on derivatives. Our unrealized loss on derivatives was approximately $53.7 million for the year ended December 31, 2019, as compared to an unrealized gain of $65.1 million for the year ended December 31, 2018. During the year ended December 31, 2019, the aggregate net fair value of our open oil and natural gas derivatives and oil basis swap contracts decreased from a net asset of approximately $49.8 million to a net liability of approximately $3.9 million, resulting in an unrealized loss on derivatives of approximately $53.7 million for the year ended December 31, 2019. During the year ended December 31, 2018, the aggregate net fair value of our open oil and natural gas derivative contracts increased from a net liability of approximately $15.2 million to a net asset of approximately $49.8 million, resulting in an unrealized gain on derivatives of approximately $65.1 million for the year ended December 31, 2018.

EXPENSES

The following table summarizes our operating expenses and other income (expense) for the periods indicated.

	Year Ended December 31,		
	2019	2018	2017
(In thousands, except expenses per BOE)			
Expenses:			
Production taxes, transportation and processing	$ 92,273	$ 76,138	$ 58,275
Lease operating	117,305	92,966	67,313
Plant and other midstream services operating	36,798	24,609	13,039
Purchased natural gas	69,398	6,635	—
Depletion, depreciation and amortization	350,540	265,142	177,502
Accretion of asset retirement obligations	1,822	1,530	1,290
General and administrative	80,054	69,308	66,016
Total expenses	748,190	536,328	383,435
Operating income	235,480	363,271	160,841
Other income (expense):			
Net (loss) gain on asset sales and inventory impairment	(967)	(196)	23
Interest expense	(73,873)	(41,327)	(34,565)
Prepayment premium on extinguishment of debt	—	(31,226)	—
Other (expense) income	(2,126)	1,551	3,551
Total other (expense) income	(76,966)	(71,198)	(30,991)
Income before income taxes	158,514	292,073	129,850
Total income tax provision (benefit)	35,532	(7,691)	(8,157)
Net income attributable to non-controlling interest in subsidiaries	(35,205)	(25,557)	(12,140)
Net income attributable to Matador Resources Company shareholders	$ 87,777	$274,207	$125,867
Expenses per BOE:			
Production taxes, transportation and processing	$ 3.82	$ 4.00	$ 4.10
Lease operating	$ 4.85	$ 4.89	$ 4.74
Plant and other midstream services operating	$ 1.52	$ 1.29	$ 0.92
Depletion, depreciation and amortization	$ 14.51	$ 13.94	$ 12.49
General and administrative	$ 3.31	$ 3.64	$ 4.65

Year Ended December 31, 2019 as Compared to Year Ended December 31, 2018

Production taxes, transportation and processing. Our production taxes and transportation and processing expenses increased $16.1 million, or 21%, to $92.3 million for the year ended December 31, 2019, as compared to $76.1 million for the year ended December 31, 2018. This increase was primarily attributable to the $5.3 million increase in our production taxes to $63.3 million for the year ended December 31, 2019, as compared to $58.0 million for the year ended December 31, 2018, resulting from the $91.6 million increase in oil and natural gas revenues for the year ended December 31, 2019, as compared to the year ended December 31, 2018. Transportation and processing expenses increased to $29.0 million for the year ended December 31, 2019, as compared to $18.2 million for the year ended December 31, 2018, primarily resulting from the 27% increase in total oil equivalent production between the respective periods. On a unit-of-production basis, our production taxes and transportation and processing expenses decreased to $3.82 per BOE for the year ended December 31, 2019, as compared to $4.00 per BOE for the year ended December 31, 2018, as the 27% increase in total oil equivalent production between the respective periods more than offset the 21% increase in our production taxes, transportation and processing expenses.

Lease operating expenses. Our lease operating expenses increased $24.3 million, or 26%, to $117.3 million for the year ended December 31, 2019, as compared to $93.0 million for the year ended December 31, 2018. The increase in lease operating expenses for the year ended December 31, 2019 was primarily attributable to an increase in the costs of services and equipment related to the increased number of wells we operated during the year ended December 31, 2019. Our lease operating expenses on a unit-of-production basis decreased 1% to $4.85 per BOE for the year ended December 31, 2019, as compared to $4.89 per BOE for the year ended December 31, 2018, as the 26% increase in total lease operating expenses was approximately offset by the 27% increase in total equivalent oil production between the respective periods.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased $12.2 million, or 50%, to $36.8 million for the year ended December 31, 2019, as compared to $24.6 million for the year ended December 31, 2018. This increase was primarily attributable to (i) increased expenses associated with our expanded commercial salt water disposal operations of $18.1 million for the year ended December 31, 2019, as compared to $13.1 million for the year ended December 31, 2018, (ii) increased expenses associated with the Black River Processing Plant, which was expanded late in the first quarter of 2018, of $11.0 million for the year ended December 31, 2019, as compared to $7.6 million for the year ended December 31, 2018, and (iii) increased expenses associated with pipeline operations of $7.9 million for the year ended December 31, 2019, as compared to $3.5 million for the year ended December 31, 2018.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased $85.4 million, or 32%, to $350.5 million for the year ended December 31, 2019, as compared to $265.1 million for the year ended December 31, 2018. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased 4% to $14.51 per BOE for the year ended December 31, 2019, as compared to $13.94 per BOE for the year ended December 31, 2018. These increases were primarily attributable to (i) a somewhat higher depletion rate in 2019 as compared to 2018, resulting from our total equivalent oil production growth being slightly greater than the growth in our total proved oil and natural gas reserves, and (ii) increased depreciation expenses associated with our expanded midstream assets of approximately $16.1 million for the year ended December 31, 2019, as compared to $10.5 million for the year ended December 31, 2018.

General and administrative. Our general and administrative expenses increased $10.7 million, or 16%, to $80.1 million for the year ended December 31, 2019, as compared to $69.3 million for the year ended December 31, 2018. The increase in our general and administrative expenses was primarily attributable to increased payroll expenses of approximately $13.8 million associated with additional employees to support our increased land, geoscience, drilling, completion, production, midstream, accounting and administration functions as a result of our continued growth. This increase was partially offset by an increase of capitalized general and administrative expenses of $3.1 million for the year ended December 31, 2019. Our general and administrative expenses decreased 9% on a unit-of-production basis to $3.31 per BOE for the year ended December 31, 2019, as compared to $3.64 per BOE for the year ended December 31, 2018, as the 27% increase in total oil equivalent production between the respective periods more than offset the 9% increase in our general and administrative expenses.

Interest expense. For the year ended December 31, 2019, we incurred total interest expense of approximately $82.4 million. We capitalized approximately $8.5 million of our interest expense on certain qualifying projects for the year ended December 31, 2019 and expensed the remaining $73.9 million to operations. For the year ended

December 31, 2018, we incurred total interest expense of approximately $50.2 million. We capitalized $8.8 million of our interest expense on certain qualifying projects for the year ended December 31, 2018 and expensed the remaining $41.3 million to operations. The increase in total interest expense for the year ended December 31, 2019, as compared to the year ended December 31, 2018, was primarily attributable to an increase in our average debt outstanding. In August and September 2018, we completed a tender offer and redemption of our $575.0 million aggregate principal amount of 6.875% senior notes due 2023 (the "2023 Notes"). In August 2018, we issued $750.0 million aggregate principal amount of 5.875% notes due 2026 (the "Original 2026 Notes"), and in October 2018, we issued an additional $300.0 million aggregate principal amount of 5.875% notes due 2026 (the "Additional 2026 Notes" and, together with the Original 2026 Notes, the "2026 Notes"), increasing our total senior notes outstanding to $1.05 billion at December 31, 2018.

Prepayment premium on extinguishment of debt. For the year ended December 31, 2018, we incurred a prepayment premium on extinguishment of debt of $31.2 million resulting from the tender offer to purchase for cash and subsequent redemption of all of our 2023 Notes. There was no similar expense incurred for the year ended December 31, 2019.

Total income tax provision (benefit). We recorded a total income tax provision of $35.5 million for the year ended December 31, 2019. Total income tax expense for the year ended December 31, 2019 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to the impact of permanent differences between book and taxable income and state taxes, primarily in New Mexico.

LIQUIDITY AND CAPITAL RESOURCES

Our primary use of capital has been, and we expect will continue to be during 2020 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties and for midstream investments. Excluding any possible significant acquisitions, we expect to fund our 2020 capital expenditures through a combination of cash on hand, operating cash flows, performance incentives in connection with San Mateo, borrowings under our Credit Agreement (assuming availability under our borrowing base of $900.0 million) and borrowings under the San Mateo Credit Facility (assuming availability under the accordion feature of such facility to up to $400.0 million). In addition, in 2020, we expect to receive a portion of the $50.0 million capital carry Five Point agreed to provide to us in conjunction with the formation of San Mateo II. We continually evaluate other capital sources, including borrowings under additional credit arrangements, the sale or joint venture of midstream assets, oil and natural gas producing assets, leasehold interests or mineral interests and potential issuances of equity, debt or convertible securities, none of which may be available on satisfactory terms or at all. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital and to generate operating cash flows.

At December 31, 2019, we had cash totaling approximately $40.0 million and restricted cash totaling approximately $25.1 million, most of which was associated with San Mateo. By contractual agreement, the cash in the accounts held by our less-than-wholly-owned subsidiaries is not to be commingled with our other cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.

In October 2018, the lenders under our Credit Agreement, led by Royal Bank of Canada, completed their review of our proved oil and natural gas reserves at June 30, 2018. In connection with such review, we amended the Credit Agreement to, among other items, increase the maximum facility amount to $1.5 billion, increase the borrowing base to $850.0 million, increase the elected borrowing commitment to $500.0 million, extend the maturity to October 31, 2023, reduce borrowing rates by 0.25% per annum and set the maximum leverage ratio at 4.00 to 1.00. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, the maximum facility amount and the elected borrowing commitment.

In April 2019, the lenders under our Credit Agreement completed their review of our proved oil and natural gas reserves at December 31, 2018, and as a result, the borrowing base was increased to $900.0 million with the elected borrowing commitment remaining at $500.0 million. In October 2019, the lenders under our Credit Agreement completed their review of our proved oil and natural gas reserves at June 30, 2019, and as a result, the borrowing base was affirmed at $900.0 million with the elected borrowing commitment remaining at $500.0 million.

In February 2020, the lenders under our Credit Agreement completed their review of our proved oil and natural gas reserves at December 31, 2019, and as a result, the borrowing base was again affirmed at $900.0 million, and we increased the elected borrowing commitment from $500.0 million to $700.0 million.

In December 2018, San Mateo I entered into the San Mateo Credit Facility, a $250.0 million credit facility led by The Bank of Nova Scotia, as administrative agent, and including all lenders in the Credit Agreement at that time. The San Mateo Credit Facility, which matures December 19, 2023, includes an accordion feature, which provides for potential increases to up to $400.0 million. The San Mateo Credit Facility is guaranteed by San Mateo I's subsidiaries, secured by substantially all of San Mateo I's assets, including real property, and is non-recourse to Matador and its wholly-owned subsidiaries, as well as San Mateo II and its subsidiaries.

In June and October 2019, pursuant to the accordion feature, the lender commitments under the San Mateo Credit Facility were increased to $325.0 million and $375.0 million, respectively.

In 2019, we converted approximately $21.9 million of non-core assets to cash. These properties were primarily located in South Texas and Northwest Louisiana and East Texas but included a small portion of our leasehold in a non-operated area of the Delaware Basin.

At December 31, 2019, we had (i) $1.05 billion of outstanding 2026 Notes, (ii) $255.0 million in borrowings outstanding under the Credit Agreement and (iii) approximately $46.1 million in outstanding letters of credit issued pursuant to the Credit Agreement, and San Mateo I had $288.0 million in borrowings outstanding under the San Mateo Credit Facility and approximately $16.2 million in outstanding letters of credit issued pursuant to the San Mateo Credit Facility. At February 25, 2020, we had (x) $1.05 billion of outstanding 2026 Notes, (y) $255.0 million in borrowings outstanding under the Credit Agreement and (z) approximately $46.0 million in outstanding letters of credit issued pursuant to the Credit Agreement, and San Mateo I had $288.0 million in borrowings outstanding and approximately $16.2 million in outstanding letters of credit issued pursuant to the San Mateo Credit Facility.

We expect that development of our Delaware Basin assets will be the primary focus of our operations and capital expenditures in 2020. We plan to operate six contracted drilling rigs drilling primarily oil and natural gas wells in the Delaware Basin throughout 2020. Our 2020 estimated capital expenditure budget consists of $690.0 to $750.0 million for D/C/E capital expenditures and $85.0 to $105.0 million for midstream capital expenditures, which primarily reflects our proportionate share of San Mateo's estimated combined 2020 capital expenditures of $190.0 to $235.0 million and also accounts for the remaining portions of the $50.0 million capital carry that Five Point agreed to provide to us in conjunction with the formation of San Mateo II. Substantially all of these 2020 estimated capital expenditures will be allocated to (i) the further delineation and development of our leasehold position, (ii) the continued construction of midstream assets and (iii) our participation in certain non-operated well opportunities in the Delaware Basin, with the exception of amounts allocated to limited operations in our South Texas and Haynesville shale positions to maintain and extend leases and to participate in certain non-operated well opportunities.

Our 2020 Delaware Basin drilling program is expected to focus on the continued development of our various asset areas throughout the Delaware Basin, with a particular emphasis on drilling and completing a higher percentage of longer horizontal wells in 2020, including 74% with anticipated completed lateral lengths of two miles. We have continued to build significant optionality into our drilling program. Three of our rigs operate on longer-term contracts with remaining average terms of approximately 19 months. The other three rigs are on short-term contracts with remaining obligations of 12 months or less. This affords us the ability to modify our drilling program as we may deem necessary based on changing commodity prices and other factors.

To narrow any potential difference between our 2020 capital expenditures and operating cash flows, we may divest portions of our non-core assets, particularly in the Haynesville shale and in parts of our South Texas positions (as we did in 2019, converting $21.9 million of non-core assets to cash), as well as consider monetizing other assets, such as certain mineral, royalty and midstream interests, as value-creating opportunities arise. In addition, we intend to continue evaluating the opportunistic acquisition of acreage and mineral interests, principally in the Delaware Basin, during 2020. These monetizations, divestitures and expenditures are opportunity-specific, and purchase price multiples and per-acre prices can vary significantly based on the asset or prospect. As a result, it is difficult to estimate these 2020 monetizations, divestitures and capital expenditures with any degree of certainty; therefore, we have not provided estimated proceeds related to monetizations or divestitures or estimated capital expenditures related to acreage and mineral acquisitions for 2020.

Our 2020 capital expenditures may be adjusted as business conditions warrant and the amount, timing and allocation of such expenditures is largely discretionary and within our control. The aggregate amount of capital we will expend may fluctuate materially based on market conditions, the actual costs to drill, complete and place on production operated or non-operated wells, our drilling results, the actual costs and scope of our midstream activities, the ability of our joint venture partners to meet their capital obligations, other opportunities that may become available to us and our ability to obtain capital. When oil or natural gas prices decline, or costs increase significantly, we have the flexibility to defer a significant portion of our capital expenditures until later periods to conserve cash or to focus on projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling, completion and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in our exploration and development activities, contractual obligations, drilling plans for properties we do not operate and other factors both within and outside our control.

Exploration and development activities are subject to a number of risks and uncertainties, which could cause these activities to be less successful than we anticipate. A significant portion of our anticipated cash flows from operations for 2020 is expected to come from producing wells and development activities on currently proved properties in the Wolfcamp and Bone Spring plays in the Delaware Basin, the Eagle Ford shale in South Texas and the Haynesville shale in Northwest Louisiana. Our existing wells may not produce at the levels we are forecasting and our exploration and development activities in these areas may not be as successful as we anticipate. Additionally, our anticipated cash flows from operations are based upon current expectations of oil and natural gas prices for 2020 and the hedges we currently have in place. For further discussion of our expectations of such commodity prices, see "—General Outlook and Trends" below. We use commodity derivative financial instruments at times to mitigate our exposure to fluctuations in oil, natural gas and NGL prices and to partially offset reductions in our cash flows from operations resulting from declines in commodity prices. See Note 12 to the consolidated financial statements in this Annual Report for a summary of our open derivative financial instruments at December 31, 2019. See "Risk Factors — Our Exploration, Development, Exploitation and Midstream Projects Require Substantial Capital Expenditures That May Exceed Our Cash Flows from Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth," "Risk Factors — Drilling for and Producing Oil and Natural Gas Are Highly Speculative and Involve a High Degree of Operational and Financial Risk, with Many Uncertainties That Could Adversely Affect Our Business" and "Risk Factors — Our Identified Drilling Locations Are Scheduled over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling."

Our cash flows for the years ended December 31, 2019, 2018 and 2017 are presented below.

	Year Ended December 31,		
	2019	2018	2017
(In thousands)			
Net cash provided by operating activities	$ 552,042	$ 608,523	$ 299,125
Net cash used in investing activities	(903,976)	(1,515,253)	(819,284)
Net cash provided by financing activities	333,078	888,232	408,499
Net change in cash	$ (18,856)	$ (18,498)	$(111,660)

Cash Flows Provided by Operating Activities

Net cash provided by operating activities decreased by $56.5 million to $552.0 million for the year ended December 31, 2019, as compared to net cash provided by operating activities of $608.5 million for the year ended December 31, 2018. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased to $586.6 million for the year ended December 31, 2019 from $544.1 million for the year ended December 31, 2018. This increase was primarily attributable to higher oil and natural gas production, which was partially offset by lower oil and natural gas prices realized during the year ended December 31, 2019, as compared to the year ended December 31, 2018. Changes in our operating assets and liabilities between December 31, 2018 and December 31, 2019 resulted in a net decrease of approximately $98.9 million in net cash provided by operating activities for the year ended December 31, 2019, as compared to the year ended December 31, 2018.

Our operating cash flows are sensitive to a number of variables, including changes in our production and the volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, the actions of OPEC, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of oil and natural gas. These factors are beyond our control and are difficult to predict. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and NGL prices. For additional information on the impact of changing prices on our financial condition, see "Quantitative and Qualitative Disclosures About Market Risk." See also "Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil and Natural Gas Prices and the Continued Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations."

Cash Flows Used in Investing Activities

Net cash used in investing activities decreased by $611.3 million to $904.0 million for the year ended December 31, 2019 from $1.52 billion for the year ended December 31, 2018. This decrease in net cash used in investing activities was attributable to (i) a decrease of $627.6 million in oil and natural gas properties capital expenditures and (ii) an increase of $13.6 million in proceeds from sales of assets for the year ended December 31, 2019, both as compared to the year ended December 31, 2018. This decrease in oil and natural gas properties expenditures was partially offset by an increase of approximately $28.8 million in expenditures for midstream support equipment and facilities, which included the construction of a further expansion of the Black River Processing Plant and associated infrastructure, additional salt water disposal wells and additional pipeline infrastructure. Cash used for oil and natural gas properties capital expenditures for the year ended December 31, 2019 was primarily attributable to our operated and non-operated drilling and completion activities in the Delaware Basin and our nine-well program in South Texas concluded in the first half of 2019. In 2018, we completed the BLM Acquisition, through which we acquired 8,400 gross and net leasehold acres in Lea and Eddy Counties, New Mexico for approximately $387 million. The absence of an acquisition of similar magnitude in 2019 was the primary reason for the significant decrease in net cash used in investing activities in 2019, as compared to 2018.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities was $333.1 million for the year ended December 31, 2019, as compared to net cash provided by financing activities of $888.2 million for the year ended December 31, 2018. The net cash provided by financing activities for the year ended December 31, 2019 was primarily attributable to net borrowings under our Credit Agreement of $215.0 million, borrowings under the San Mateo Credit Facility of $68.0 million, contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries of $77.3 million and contributions related to the formation of San Mateo I of $14.7 million. These cash inflows were partially offset by distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries of $39.2 million. We conducted no equity or senior notes offerings during the year ended December 31, 2019, as compared to the year ended December 31, 2018, during which we conducted an equity offering and two senior notes offerings, which was the primary reason for the significant change in cash provided by financing activities between the respective periods.

See Note 7 to the consolidated financial statements in this Annual Report for a summary of our debt, including our Credit Agreement, the San Mateo Credit Facility and the senior notes.

OFF-BALANCE SHEET ARRANGEMENTS

From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2019, the material off-balance sheet arrangements and transactions that we have entered into include (i) non-operated drilling commitments, (ii) firm transportation, gathering, processing and disposal commitments and (iii) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices or interest rates, gathering, treating and transportation commitments on uncertain volumes of future throughput, open delivery commitments and indemnification obligations following certain divestitures. Other than the off-balance sheet arrangements described above, we have no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources. See "—Obligations and Commitments" below and Note 14 to the consolidated financial statements in this Annual Report for more information regarding our off-balance sheet arrangements. Such information is incorporated herein by reference.

OBLIGATIONS AND COMMITMENTS

We had the following material contractual obligations and commitments at December 31, 2019.

		Payments Due by Period			
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
(In thousands)					
Contractual Obligations:					
Revolving credit borrowings, including letters of credit (1)	$ 605,351	$ —	$ —	$605,351	$ —
Senior unsecured notes (2)	1,050,000	—	—	—	1,050,000
Office leases	26,374	4,001	8,013	8,529	5,831
Non-operated drilling commitments (3)	26,943	26,943	—	—	—
Drilling rig contracts (4)	41,681	28,195	13,486	—	—
Asset retirement obligations (5)	36,211	620	3,104	1,656	30,831
Natural gas transportation, gathering and processing agreements with non-affiliates (6)	645,984	55,401	134,857	134,888	320,838
Gathering, processing and disposal agreements with San Mateo (7)	516,646	—	65,267	163,614	287,765
Natural gas engineering, construction and installation contract (8)	40,254	40,254	—	—	—
Total contractual cash obligations	$2,989,444	$155,414	$224,727	$914,038	$1,695,265

(1) The amounts included in the table above represent principal maturities only. At December 31, 2019, we had $255.0 million of borrowings outstanding under the Credit Agreement and approximately $46.1 million in outstanding letters of credit issued pursuant to the Credit Agreement. The Credit Agreement matures in October 2023. At December 31, 2019 San Mateo I had $288.0 million of borrowings outstanding under the San Mateo Credit Facility and approximately $16.2 million in outstanding letters of credit issued pursuant to the San Mateo Credit Facility. The San Mateo Credit Facility matures in December 2023. Assuming the amounts outstanding and interest rates of 3.28% and 3.55% (for the Credit Agreement and the San Mateo Credit Facility), respectively, at December 31, 2019, the interest expense is expected to be approximately $8.4 million and $10.4 million each year until maturity.

(2) The amounts included in the table above represent principal maturities only. Interest expense on the $1.05 billion of Notes that were outstanding as of December 31, 2019 is expected to be approximately $61.7 million each year until maturity.

(3) At December 31, 2019, we had outstanding commitments to participate in the drilling and completion of various non-operated wells. Our working interests in these wells are typically small, and certain of these wells were in progress at December 31, 2019. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $26.9 million at December 31, 2019, which we expect to incur within the next year.

(4) We do not own or operate our own drilling rigs, but instead we enter into contracts with third parties for such drilling rigs. See Note 14 to the consolidated financial statements in this Annual Report for more information regarding these contractual commitments.

(5) The amounts included in the table above represent discounted cash flow estimates for future asset retirement obligations at December 31, 2019.

(6) In late 2015, we entered into a 15-year fixed-fee natural gas gathering and processing agreement for a significant portion of our operated natural gas production in Loving County, Texas. In late 2017, we entered into an 18-year fixed-fee natural gas transportation agreement whereby we committed to deliver a portion of the residue gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline in Eddy County, New Mexico. In late 2017, we also entered into a fixed-fee NGL transportation and fractionation agreement whereby we committed to deliver our NGL production at the tailgate of the Black River Processing Plant. We have committed to deliver a minimum amount of NGLs to the counterparty upon construction and completion of a pipeline expansion and a fractionation facility by the counterparty, which is currently expected to be completed in 2020. We have no rights to compel the counterparty to construct this pipeline extension or fractionation facility. If the counterparty does not construct the pipeline extension and fractionation facility, then we do not have any minimum volume commitments under the agreement. If the counterparty constructs the pipeline extension and fractionation facility on or prior to February 28, 2021, then we will have a commitment to deliver a minimum amount of NGLs for seven years following the completion of the pipeline extension and fractionation facility. If we do not meet our NGL volume commitment in any quarter during the seven-year commitment period, we will be required to pay a deficiency fee per gallon of NGL deficiency. The amounts in the table assume that the seven-year period containing minimum NGL volume commitments begins in 2020. In the second quarter of 2018, we entered into a 16-year, fixed-fee natural gas transportation agreement that begins on October 1, 2019 whereby we committed to deliver a portion of the residue gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline. Additionally, in the second quarter of 2018, we entered into a short-term natural gas transportation agreement whereby we committed to deliver a portion of the residue gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline. In the second quarter of 2018, we entered into a 10-year, fixed-fee natural gas sales agreement whereby we committed to deliver residue gas through the counterparty's pipeline to the Texas Gulf Coast beginning on the in-service date for such pipeline, which became operational in late September 2019. Lastly, in October 2019, we entered into a 15-year, fixed-fee natural gas transportation agreement whereby we committed to deliver a portion of the residue gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline. See Note 14 to the consolidated financial statements in this Annual Report for more information regarding these contractual commitments.

(7) In February 2017, in connection with the formation of San Mateo I, we dedicated our current and certain future leasehold interests in the Rustler Breaks and Wolf asset areas pursuant to 15-year, fixed-fee natural gas, oil and salt water gathering agreements and salt water disposal agreements. In addition, effective February 1, 2017, we dedicated our current and certain future leasehold interests in the Rustler Breaks asset area pursuant to a 15-year, fixed-fee natural gas processing agreement. In February 2019, in connection with the formation of San Mateo II, we dedicated our current and certain future leasehold interests in the Greater Stebbins Area and the Stateline asset area pursuant to 15-year, fixed-fee agreements for oil, natural gas and salt water gathering, natural gas processing and salt water disposal. See Note 14 to the consolidated financial statements in this Annual Report for more information regarding these contractual commitments.

(8) Beginning in June 2019, a subsidiary of San Mateo II entered into an agreement with third parties for the engineering, procurement, construction and installation of an expansion of the Black River Processing Plant, including required compression. See Note 14 to the consolidated financial statements in this Annual Report for more information regarding these contractual commitments.

GENERAL OUTLOOK AND TRENDS

Our business success and financial results are dependent on many factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. Commodity price volatility, in particular, is a significant risk to our business and results of operations. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, the actions of OPEC, weather, pipeline capacity constraints, inventory storage levels, oil and natural gas price differentials and other factors.

In 2019, oil prices generally declined from the prices we experienced in 2018 and remained significantly below their most recent highs in 2014. For the year ended December 31, 2019, oil prices averaged $57.01 per Bbl, as compared to $64.89 per Bbl for the year ended December 31, 2018, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. During 2019, oil prices began the year at $45.41 per Bbl, which was the low for the year, and increased steadily, reaching a high of $66.30 per Bbl in late April. Oil prices declined during the third quarter of 2019 before increasing again during the fourth quarter of 2019 to finish the year at $61.06 per Bbl. In early 2020, oil prices have been particularly volatile, ranging from a high of $65.00 per Bbl in early January to below $45.00 per Bbl in late February.

We realized a weighted average oil price of $54.34 per Bbl ($54.98 per Bbl including realized gains from oil derivatives) for our oil production for the year ended December 31, 2019, as compared to $57.04 per Bbl ($57.38 per Bbl including realized gains from oil derivatives) for the year ended December 31, 2018. At February 25, 2020, the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date had declined from year-end 2019, closing at $49.90 per Bbl, and was lower compared to $55.48 per Bbl on February 25, 2019.

Natural gas prices dropped significantly during much of 2019. For the year ended December 31, 2019, natural gas prices averaged $2.53 per MMBtu, as compared to $3.07 per MMbtu for the year ended December 31, 2018, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. During 2019, natural gas prices began the year at $2.94 per MMBtu and reached a high of $3.59 per MMBtu in mid-January, before declining to low of $2.07 per MMBtu in early August and finishing the year at $2.19 per MMBtu.

We realized a weighted average natural gas price of $2.17 per Mcf ($2.18 per Mcf including realized gains from natural gas derivatives) for our natural gas production for the year ended December 31, 2019, as compared to $3.49 per Mcf ($3.46 per Mcf including realized losses from natural gas derivatives) for the year ended December 31, 2018. As a two-stream reporter, the revenues associated with our NGL production are included in the weighted average natural gas price. NGL prices were weaker in 2019, as compared to 2018. At February 25, 2020, the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date had declined further from year-end 2019, closing at $1.85 per MMBtu, and was significantly lower as compared to $2.84 per MMBtu at February 25, 2019.

The prices we receive for oil, natural gas and NGLs heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil, natural gas and NGL prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, natural gas and NGLs have been volatile, and these markets will likely continue to be volatile in the future. Recently, oil prices have experienced a significant decrease as a result of the perceived impact upon global demand for oil due to the outbreak of the coronavirus. Declines in oil, natural gas or NGL prices not only reduce our revenues, but could also reduce the amount of oil, natural gas and NGLs we can produce economically, and, as a result, could have an adverse effect on our financial condition, results of operations, cash flows and reserves. We are uncertain if oil and natural gas prices may rise from their current levels, and in fact, oil and natural gas prices may decrease in future periods. See "Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil and Natural Gas Prices and the Continued Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations."

From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and NGL prices. Even so, decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and NGL prices, and we may not always employ the optimal hedging strategy. This, in turn, may affect the liquidity that can be accessed through the borrowing base under our Credit Agreement and through the capital markets.

In addition, the prices we receive for oil and natural gas production often reflect a discount to the relevant benchmark prices, such as the NYMEX West Texas Intermediate oil price or the NYMEX Henry Hub natural gas price. The difference between the benchmark price and the price we receive is called a differential. At December 31, 2019, most of our oil production from the Delaware Basin was sold based on prices established in Midland, Texas. For the first nine months of 2019, most of our natural gas production from the Delaware Basin was sold based on prices established at the Waha Hub in far West Texas. At the end of September 2019, the GCX Pipeline became operational. We have secured firm natural gas transportation and sales on the GCX Pipeline for an average of approximately 110,000 to 115,000 MMBtu per day at a natural gas price based upon Houston Ship Channel pricing.

During the second quarter of 2018, the price differentials for oil sold in Midland and natural gas sold at Waha compared to the benchmark prices for oil and natural gas, respectively, began to widen significantly and continued to widen throughout most of the year. These widening basis differentials negatively impacted our oil and natural gas revenues in 2018 and throughout most of 2019.

During 2018, the Midland-Cushing (Oklahoma) oil price differential increased substantially from essentially no difference in the first quarter to as much as $16.00 per Bbl in late September but narrowed to about $5.00 per Bbl at the beginning of 2019. The Midland-Cushing (Oklahoma) oil price differential narrowed further to less than $1.00 per Bbl during the first quarter of 2019 but widened again during the second quarter to levels experienced at the beginning of the year. The Midland-Cushing (Oklahoma) oil price differential narrowed again in the third quarter of 2019, became positive late in the third quarter and remained positive throughout the fourth quarter of 2019. As of February 25, 2020, this oil price differential had remained positive in 2020, although it is possible that this differential could turn negative again at certain times during the remainder of 2020.

Our realized price for a portion of our Delaware Basin natural gas production is exposed to the Waha-Henry Hub basis differential. This natural gas price differential increased significantly throughout 2018 from about $0.50 per MMBtu at the beginning of the year to between $1.00 and $2.00 per MMBtu for most of 2018, but reaching highs of greater than $4.00 per MMBtu for a brief period near the end of the year. The natural gas price differential narrowed to between $1.00 and $2.00 per MMBtu at the beginning of 2019 and remained there throughout much of the first quarter.

The natural gas basis differentials widened significantly in April 2019 for a short period of time, including a few days when natural gas was being sold at Waha for negative prices as high as ($7.00) to ($9.00) per MMBtu on a daily market basis, resulting, in part, from a number of simultaneous outages and maintenance projects impacting major pipelines in the area. Natural gas prices at Waha were positive for most of the latter part of April 2019, but daily market prices for natural gas sold at Waha reached negative levels of ($2.00) to ($3.00) per MMBtu in late May. In response to these basis differentials, we temporarily shut in certain high gas-oil ratio wells and took other actions to mitigate the impact of these negative prices on our results.

During the second half of 2019, the Waha basis differentials improved, and natural gas prices at the Waha hub averaged approximately $1.00 per MMBtu for the final six months of the year. As a result, we did not need to shut in certain high gas-to-oil ratio wells or take other actions to curtail our Delaware Basin natural gas production during this period. Despite improving during the second half of 2019, beginning in the fourth quarter, the Waha basis differentials widened further at times, and natural gas prices at the Waha hub were slightly negative on certain days in late December 2019. In early 2020, the outlook for the Waha basis differentials has deteriorated further, with the futures markets indicating Waha basis differentials between $1.20 and $2.00 per MMBtu throughout 2020 as of mid-February.

Beginning in late September 2019, as the GCX Pipeline became operational, we began selling a majority of our produced Delaware Basin natural gas at Houston Ship Channel pricing, and we realized an improvement in the natural gas pricing received despite higher transportation charges incurred to transport the natural gas to the Gulf Coast. Further, approximately 32% of our reported natural gas production in the third and fourth quarters of 2019 was attributable to the Haynesville and Eagle Ford shale plays, which are not exposed to Waha pricing. In addition, as a two-stream reporter, most of our natural gas volumes in the Delaware Basin are processed for NGLs, resulting in a further reduction in the reported natural gas volumes exposed to Waha pricing.

These widening oil and natural gas basis differentials are largely attributable to industry concerns regarding the near-term sufficiency of pipeline takeaway capacity for oil, natural gas and NGL production in the Delaware Basin. At February 25, 2020, we had not experienced material pipeline-related interruptions to our oil, natural gas or NGL production. In certain recent periods, shortages of NGL fractionation capacity were experienced by certain operators in the Delaware Basin. Although we did not encounter such fractionation capacity problems, we can provide no assurances that such problems will not arise. If we do experience any interruptions with takeaway capacity or NGL fractionation, our oil and natural gas revenues, business, financial condition, results of operations and cash flows could be adversely affected.

We anticipate that the volatility in these oil and natural gas price differentials could persist throughout 2020 or longer until additional oil and natural gas pipeline capacity from West Texas to the Texas Gulf Coast and other end markets is completed. We can provide no assurances as to how long these volatile differentials may persist, and as noted above, these price differentials could widen further in future periods. Should we experience future periods of negative pricing for natural gas as we did during the second quarter of 2019, we may temporarily shut in certain high gas-oil ratio wells and take other actions to mitigate the impact on our realized natural gas prices and results. In addition, we have no derivative contracts in place to mitigate our exposure to these natural gas price differentials during 2020.

Our oil and natural gas exploration, development, production, midstream and related operations are subject to extensive federal, state and local laws, rules and regulations. The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these laws, rules and regulations are frequently amended or reinterpreted and new laws, rules and regulations are proposed or promulgated, we are unable to predict the future cost or impact of complying with the laws, rules and regulations to which we are, or will become, subject. For example, in 2019 and 2020, separate bills were introduced in the New Mexico Senate proposing to add a surtax on natural gas processors and proposing to place a moratorium on hydraulic fracturing. In 2019, New Mexico's governor also signed an executive order requiring a regulatory framework to ensure reductions of methane emissions. Although such bills have not passed, these and other laws, rules and regulations, including any federal legislation, regulations or orders intended to limit or restrict oil and natural gas operations on federal lands, if enacted, could have an adverse impact on our business, financial condition, results of operations and cash flows. In addition, certain segments of the investor community have recently expressed negative sentiment towards investing in the oil and natural gas industry, recent equity returns in the sector versus other industry sectors have led to lower oil and natural gas representation in certain key equity market indices and some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and natural gas sector based on social and environmental considerations.

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our oil and natural gas wells will experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil, natural gas and NGL price declines, however, drilling additional oil or natural gas wells may not be economic, and we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves, cash flows and our availability under our Credit Agreement. See "Risk Factors — Our Exploration, Development, Exploitation and Midstream Projects Require Substantial Capital Expenditures That May Exceed Our Cash Flows from Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth."

We strive to focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of certain assets, liabilities, revenues and expenses during each reporting period. We believe that our estimates and assumptions are reasonable and reliable and that the actual results will not differ significantly from those reported; however, such estimates and assumptions are subject to a number of risks and uncertainties, and such risks and uncertainties could cause the actual results to differ materially from our estimates. We consider the following to be our most critical accounting policies and estimates involving significant judgment or estimates by our management. See Note 2 to the consolidated financial statements in this Annual Report for further details on our accounting policies at December 31, 2019.

Oil and Natural Gas Properties

We use the full-cost method of accounting for our investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to acquisition, exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities.

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved reserves quantities. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the amortization base. Exploratory dry holes are included in the amortization base immediately upon the determination that the well is not productive.

Sales of oil and natural gas properties are accounted for as adjustments to net capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between net capitalized costs and proved reserves of oil and natural gas. All costs related to production activities and maintenance and repairs are expensed as incurred. Significant workovers that increase the properties' reserves are capitalized.

Ceiling Test

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center "ceiling." The cost center ceiling is defined as the sum of:

(a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus

(b) unproved and unevaluated property costs not being amortized, plus

(c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less

(d) any income tax effects related to the properties involved.

Any excess of our net capitalized costs above the cost center ceiling as described above is charged to operations as a full-cost ceiling impairment. The fair value of our derivative instruments is not included in the ceiling test computation as we do not designate these instruments as hedge instruments for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent upon the quantities of proved reserves, the estimation of which requires substantial judgment. The associated commodity prices and the applicable discount rate used in these estimates are in accordance with guidelines established by the SEC. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. Future net revenues are calculated using prices that represent the arithmetic averages of the first-day-of-the-month oil and natural gas prices for the previous 12-month period, and a 10% discount factor is used to determine the present value of future net revenues.

Because the cost center ceiling calculation is based on the average of historical prices, which may or may not be representative of future prices, and requires a 10% discount factor, the resulting estimated value may not be indicative of the fair market value of our properties. Any impairment related to the excess of our net capitalized costs above the resulting cost center ceiling should not be viewed as an absolute indicator of a reduction in the ultimate value of the related oil and natural gas reserves.

Derivative Financial Instruments

From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and NGL prices. These instruments typically consist of put and call options in the form of costless (or zero-cost) collars and swap contracts. Costless collars provide us with downside price protection through the purchase of a put option that is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially "costless" to us. Three-way costless collars also provide us with downside price protection through the purchase of a put option, but they also allow us to participate in price upside through the purchase of a call option. The purchase of both the put option and call option are financed through the sale of a call option. Because the proceeds from the call option sale are used to offset the cost of the purchased put and call options, these arrangements are also initially "costless" to us.

In the case of a costless collar, the put option and the call option or options have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified period, providing downside price protection.

Prior to settlement, our derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. We have elected not to apply hedge accounting for our existing derivative financial instruments, and as a result, we recognize the change in derivative fair value between reporting periods currently in our consolidated statements of operations. Such changes in fair value are reported under Revenues as "Unrealized gain (loss) on derivatives." Changes in the fair value of these open derivative financial instruments can have a significant impact on our reported results from period to period but do not impact our cash flows from operations, liquidity or capital resources. The fair value of our open derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Realized gains and realized losses from the settlement of derivative financial instruments do have a direct impact on our cash flow from operations and liquidity. The impact of these settlements is also reported under Revenues as "Realized gain (loss) on derivatives."

Revenue Recognition

During the first quarter of 2018, we adopted Accounting Standards Update 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASC 606"), which specifies how and when to recognize revenue. This standard requires expanded disclosures surrounding revenue recognition and is intended to improve the financial reporting requirements for revenue from contracts with customers and converge these requirements with international standards. We adopted the new guidance using the modified retrospective approach. The adoption did not require an adjustment to opening accumulated deficit for any cumulative effect adjustment and did not have a material impact on our consolidated balance sheets, statements of operations, statement of shareholders' equity or statements of cash flows.

Prior to the adoption of ASC 606, we recorded oil and natural gas revenues at the time of physical transfer of such products to the purchaser. We followed the sales method of accounting for oil and natural gas sales, recognizing revenues based on our actual proceeds from the oil and natural gas sold to purchasers.

We enter into contracts with customers to sell our oil and natural gas production. With the adoption of ASC 606, revenue from these contracts is recognized in accordance with the five-step revenue recognition model prescribed in ASC 606. Specifically, revenue is recognized when our performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights. Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration we expect to receive in accordance with the price specified in the contract. Consideration under the oil and natural gas marketing contracts is typically received from the purchaser one to two months after production.

The majority of our oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the oil has been transferred to the purchaser. The majority of the oil produced is sold under contracts using market-based pricing, which price is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred at or after the transfer of control of the oil, the differentials are included in oil revenues on the statements of operations, as they represent part of the transaction price of the contract. If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in production taxes, transportation and processing expenses on our consolidated statements of operations, as they represent payment for services performed outside of the contract with the customer.

Our natural gas is sold at the lease location, at the inlet or outlet of a natural gas processing plant or at an interconnect near a marketing hub following transportation from a processing plant. The majority of our natural gas is sold under fee-based contracts. When the natural gas is sold at the lease, the purchaser gathers the natural gas and transports the natural gas via pipeline to natural gas processing plants where, if necessary, NGLs are extracted. The NGLs and remaining residue gas are then sold by the purchaser, or if we elect to take in-kind the natural gas or NGLs, we sell the natural gas or NGLs to a third party. Under the fee-based contracts, we receive NGL and residue gas value, less the fee component, or are invoiced the fee component. To the extent control of the natural gas transfers upstream of the transportation and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those services, revenue is recognized on a gross basis, and the related costs are included in production taxes, transportation and processing expenses on our consolidated statements of operations.

We recognize midstream services revenues at the time services have been rendered and the price is fixed and determinable. Third-party midstream services revenues are those revenues from midstream operations related to third parties, including working interest owners in our operated wells. All midstream services revenues related to our working interest are eliminated in consolidation. Since we have a right to payment from our customers in amounts that correspond directly to the value that the customer receives from the performance completed on each contract, we apply the practical expedient in ASC 606 that allows recognition of revenue in the amount for which there is a right to invoice the customer without estimating a transaction price for each contract and allocating that transaction price to the performance obligations within each contract.

We periodically enter into natural gas purchase transactions with third parties whereby we process a third party's natural gas at the Black River Processing Plant and then purchase, and subsequently sell, the residue gas and NGLs to other purchasers. Revenues and expenses from these transactions are presented on a gross basis on our consolidated statements of operations as we act as a principal in the transactions by assuming the risk and rewards of ownership, including credit risk, of the natural gas purchased and by assuming the responsibility to deliver and process the natural gas volumes to be sold.

From time to time, we, as an owner of mineral interests, may enter into or extend a lease to a third-party lessee to develop the oil and natural gas attributable to certain of our mineral interests in return for a specified payment or lease bonus. In those instances, revenue is recognized in the period when the lease is signed, and we have no further obligation to the lessee. We record these payments as "Lease bonus - mineral acreage" revenues on our consolidated statements of operations.

Stock-Based Compensation

We may grant equity-based and liability-based common stock, stock options, restricted stock, restricted stock units, performance stock units and other awards permitted under any long-term incentive plan then in effect to members of our Board of Directors and certain employees, contractors and advisors. We use the fair value method to measure and recognize the liability associated with our outstanding liability-based stock options (all of which were settled in the first quarter of 2020) and to measure and recognize the equity associated with our equity-based stock options. Stock options typically vest over three or four years, and the associated compensation expense is recognized on a straight-line basis over the vesting period. Restricted stock and restricted stock units typically vest over a period of one to four years, and compensation expense is recognized on a straight line basis over the vesting period. We use our own historical volatility to estimate the future volatility of our stock.

We have adopted the "simplified method" as outlined in Staff Accounting Bulletin Topic 14 for estimating the expected term of awards. The risk free interest rate is the rate for constant yield U.S. Treasury securities with a term to maturity that is consistent with the expected term of the award.

Assumptions are reviewed each time new equity-based option awards are granted and were reviewed quarterly for outstanding liability-based option awards. The assumptions used may be impacted by actual fluctuations in our stock price, movements in market interest rates and option terms. The use of different assumptions produces a different fair value for equity-based option awards and outstanding liability-based option awards and can significantly impact the amount of stock compensation expense recognized in our consolidated statement of operations or capitalized in accordance with our policy on capitalizing general and administrative expenses for employees involved in acquisition, exploration and development activities. We use the Black Scholes Merton model to determine the fair value of service-based option awards and the Monte Carlo method to determine the fair value of awards that contain a market condition. The fair value of restricted stock and restricted stock unit awards is recognized based on the closing price of our common stock on the date of the grant for awards issued under the 2003 Plan and on the trading day prior to the date of grant for awards issued under the 2019 Incentive Plan. See Note 9 to the consolidated financial statements in this Annual Report for further details on our stock-based compensation at December 31, 2019.

Income Taxes

We account for income taxes using the asset and liability approach for financial accounting and reporting. The amount of income taxes recorded requires interpretations of complex rules and regulations of federal and state taxing authorities. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and tax carryforwards. We evaluate the probability of realizing the future benefits of our deferred tax assets and provide a valuation allowance for the portion of any deferred tax assets where the likelihood of realizing an income tax benefit in the future does not meet the more likely than not criteria for recognition.

We account for uncertainty in income taxes by recognizing the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. See Note 8 to the consolidated financial statements in this Annual Report for additional information of the impact of the 2017 Tax Cuts and Jobs Act to our consolidated financial statements.

Oil and Natural Gas Reserves Quantities and Standardized Measure of Future Net Revenue

Our engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. While the applicable rules allow us to disclose proved, probable and possible reserves, we have elected to present only proved reserves in this Annual Report. The applicable rules define proved reserves as the quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project within a reasonable time.

Our engineers and technical staff must make many subjective assumptions based on their professional judgment in developing reserves estimates. Reserves estimates are updated quarterly and consider recent production levels and other technical information about each well. Estimating oil and natural gas reserves is complex and inexact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of both the data and the associated interpretations can vary. The process also requires certain economic assumptions, including, but not limited to, oil and natural gas prices, development expenditures, operating expenses, capital expenditures and taxes. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas will most likely vary from our estimates. Accordingly, reserves estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. Any significant variance could materially and adversely affect our future reserves estimates, financial condition, results of operations and cash flows. We cannot predict the amounts or timing of future reserves revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in an impairment of assets that may be material. See “Risk Factors — Our Oil and Natural Gas Reserves Are Estimated and May Not Reflect the Actual Volumes of Oil and Natural Gas We Will Recover, and Significant Inaccuracies in These Reserves Estimates or Underlying Assumptions Will Materially Affect the Quantities and Present Value of Our Reserves.”

Leases

On January 1, 2019, the Company began recording in the consolidated balance sheet certain of the Company’s compressor leases, drilling rig leases and office leases, which were previously considered operating leases and not reported on the Company’s consolidated balance sheets. The present value of the related lease payments is recorded as a liability and an equal amount is capitalized as a right of use asset on the Company’s consolidated balance sheet. Right of use assets represent the Company’s right to use an underlying asset for the lease term and lease liabilities represent the Company’s obligation to make lease payments arising from the lease. The Company’s estimated incremental borrowing rate, determined at the lease commencement date using the Company’s average secured borrowing rate, is used to calculate present value. For these purposes, the lease term includes options to extend the lease when it is reasonably certain that the Company will exercise such option. Leases with terms of 12 months or less at inception are not recorded on the consolidated balance sheet unless there is a significant cost to terminate the lease, including the cost of removal of the leased asset. As the Company is the responsible party under these arrangements, the Company records the resulting assets and liabilities on a gross basis in its consolidated balance sheets.

Recent Accounting Pronouncements

See Note 2 to the consolidated financial statements in this Annual Report for a description of recent accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative financial instruments, but we do not enter into derivative financial instruments for trading purposes.

Commodity price exposure. We are exposed to market risk as the prices of oil, natural gas and NGLs fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative financial instruments in the past and expect to enter into derivative financial instruments in the future to cover a significant portion of our anticipated future production.

We typically use costless (or zero-cost) collars, three-way collars and/or swap contracts to manage risks related to changes in oil, natural gas and NGL prices. Costless collars provide us with downside price protection through the purchase of a put option that is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially "costless" to us. Three-way costless collars also provide us with downside price protection through the purchase of a put option, but they also allow us to participate in price upside through the purchase of a call option. The purchase of both the put option and call option are financed through the sale of a call option. Because the proceeds from the call option sale are used to offset the cost of the purchased put and call options, these arrangements are also initially "costless" to us. In the case of a costless collar, the put option or options and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified period, providing downside price protection.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using purchase and sale information available for similarly traded securities. At December 31, 2019, The Bank of Nova Scotia and BMO Harris Financing (Bank of Montreal) (or affiliates thereof) were the counterparties for all of our derivative instruments. We have considered the credit standing of the counterparties in determining the fair value of our derivative financial instruments.

At December 31, 2019, we had entered into various costless collar contracts to mitigate our exposure to fluctuations in oil prices, each with an established price floor and ceiling. When the settlement price is below the price floor established by one or more of these collars, we receive from our counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil volume. When the settlement price is above the price ceiling established by one or more of the costless collars, we pay our counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

During the year ended December 31, 2019, we entered into various swap contracts to mitigate our exposure to price differences between NYMEX West Texas Intermediate Cushing and Argus West Texas Intermediate Midland crude oil. When the settlement price is below the fixed price established by one or more of these swaps, we receive from the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume. When the settlement price is above the fixed price established by one or more of these swaps, we pay to the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume.

See Note 12 to the consolidated financial statements in this Annual Report for a summary of our open derivative financial instruments at December 31, 2019. Such information is incorporated herein by reference.

Effect of Derivatives Legislation. The Dodd-Frank Act, among other things, established federal oversight and regulation of certain derivative products, including commodity hedges of the type we use. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when, or if, this will be accomplished. Based upon the limited assessments we are able to make with respect to the Dodd-Frank Act, there is the possibility that the Dodd-Frank Act could have a substantial and adverse impact on our ability to enter into and maintain these commodity hedges. In particular, the Dodd-Frank Act could result in the implementation of position limits and additional regulatory requirements on our derivative arrangements, which could include new margin, reporting and clearing requirements. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future. See "Risk Factors — The Derivatives Legislation Adopted by Congress Could Have an Adverse Impact on Our Ability to Hedge Risks Associated with Our Business."

Interest rate risk. We do not and have not used interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense on existing debt since we borrowed under our Credit Agreement for the first time in December 2010. At December 31, 2019, we had outstanding borrowings of $255.0 million at an interest rate of 3.28% per annum under our Credit Agreement, $1.05 billion in Notes outstanding at a coupon rate of 5.875% per annum and $288.0 million of outstanding borrowings under the San Mateo Credit Facility at an interest rate of 3.55% per annum. If we incur additional indebtedness in the future and at higher interest rates, we may use interest rate derivatives. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Counterparty and customer credit risk. Joint interest receivables arise from billing entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial condition, results of operations and cash flows. In addition, our derivative arrangements expose us to credit risk in the event of nonperformance by our counterparties.

While we do not require our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation requires us to conduct the due diligence necessary to determine credit terms and credit limits, which may include (i) reviewing a counterparty's credit rating, latest financial information and, in the case of a customer with which we have receivables, its historical payment record and the financial ability of its parent company to make payment if the customer cannot and (ii) undertaking the due diligence necessary to determine credit terms and credit limits. The counterparties on our derivative financial instruments in place at February 25, 2020 were The Bank of Nova Scotia and BMO Harris Financing (Bank of Montreal) (or affiliates thereof), which are lenders (or affiliates thereof) under our Credit Agreement, and we are likely to enter into any future derivative instruments with such banks or other lenders (or affiliates thereof) party to the Credit Agreement.

Impact of Inflation. Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2019, 2018 and 2017. Although the impact of inflation has been generally insignificant in recent years, it is still a factor in the U.S. economy and we tend to specifically experience inflationary pressure on the cost of oilfield services and equipment with increases in oil and natural gas prices and with increases in drilling activity in our areas of operations, including the Wolfcamp and Bone Spring plays in the Delaware Basin, the Eagle Ford shale play and the Haynesville shale play. See "Risk Factors — The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Our financial statements appear at the end of this Annual Report beginning on page F-1.

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

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Annual Report, we evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2019 to ensure that (i) information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that (ii) information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2019, there were no changes in our internal controls that have materially affected or are reasonably likely to have a material effect on our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act, as amended. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this Annual Report based on the framework in 2013 "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

KPMG, our independent registered public accounting firm, has issued an attestation report on our controls over financial reporting as of December 31, 2019 as included herein.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Matador Resources Company:

Opinion on Internal Control Over Financial Reporting

We have audited Matador Resources Company and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2019 and 2018, the related consolidated statements of operations, changes in shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements), and our report dated March 2, 2020 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ KPMG LLP

Dallas, Texas
March 2, 2020

ITEM 9B. OTHER INFORMATION.

On September 28, 2012, Matador, as a guarantor, along with certain other guarantors thereto, MRC Energy Company, a wholly-owned subsidiary of Matador ("MRC"), as borrower, the lenders party thereto (the "Lenders") and Royal Bank of Canada, as administrative agent, entered into the Credit Agreement. For a summary of key terms of the Credit Agreement, see Note 7 to the consolidated financial statements in this Annual Report, which description is incorporated herein by reference. On February 27, 2020, MRC, as borrower, entered into an amendment (the "Amendment") to the Credit Agreement, and Matador reaffirmed its guaranty of MRC's obligations under the Credit Agreement. The Amendment affirmed the $900.0 million borrowing base, increased the elected borrowing commitment from $500.0 million to $700.0 million and added two lenders.

The foregoing description of the Amendment does not purport to be complete and is qualified in its entirety by reference to the full text of the Amendment, which is included in this Annual Report as Exhibit 10.55 and is incorporated herein by reference.

Part III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement for our 2020 Annual Meeting of Shareholders to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report (our "Definitive Proxy Statement"). Such responsive information is expected to be included under the captions "Proposal 1—Election of Directors," "Corporate Governance," "Executive Compensation" and "Director Compensation."

ITEM 11. EXECUTIVE COMPENSATION.

The information required in response to this Item 11 is incorporated herein by reference to our Definitive Proxy Statement under the caption "Executive Compensation."

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

Certain information regarding securities authorized for issuance under our equity compensation plans is included under the caption "Equity Compensation Plan Information" in Part II, Item 5 of this Annual Report and is incorporated herein by reference. Other information required in response to this Item 12 is incorporated herein by reference to our Definitive Proxy Statement under the caption "Security Ownership of Certain Beneficial Owners and Management."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required in response to this Item 13 is incorporated herein by reference to our Definitive Proxy Statement under the captions "Transactions with Related Persons" and "Corporate Governance—Independence of Directors."

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required in response to this Item 14 is incorporated herein by reference to our Definitive Proxy Statement under the caption "Proposal 3—Ratification of Appointment of KPMG LLP."

Part IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as part of this Annual Report:

1. Index to Consolidated Financial Statements, Report of Independent Registered Public Accounting Firm, Consolidated Balance Sheets as of December 31, 2019 and 2018, Consolidated Statements of Operations for the Years Ended December 31, 2019, 2018 and 2017, Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2019, 2018 and 2017 and Consolidated Statements of Cash Flows for the Years Ended December 31, 2019, 2018 and 2017.
2. *Financial Statement Schedules:* All other schedules for which provision is made in the applicable accounting regulation of the SEC are omitted because the required information is either not applicable, not required or is shown in the respective financial statements or in the notes thereto.
3. *Exhibits:* The exhibits required to be filed by this Item 15 are set forth in the Exhibit Index included below.

ITEM 16. FORM 10-K SUMMARY.

None.

Exhibit Index

Exhibit Number	Description
2.1	Subscription and Contribution Agreement, dated as of February 17, 2017, by and among Longwood Midstream Holdings, LLC, FP MMP Holdings LLC and San Mateo Midstream, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on February 24, 2017).*
3.1	Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.2	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company dated April 2, 2015 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.3	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company effective June 2, 2017 (incorporated by reference to Exhibit 3.4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.4	Amended and Restated Bylaws of Matador Resources Company, as amended (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 22, 2018).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1 filed on January 19, 2012).
4.2	Indenture, dated as of August 21, 2018, by and among Matador Resources Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on August 21, 2018).
4.3	First Supplemental Indenture, dated as of February 27, 2019, by and among Matador Resources Company, WR Permian, LLC, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Annual Report on Form 10-K for the year ended December 31, 2018).
4.4	Description of Capital Stock (filed herewith).
10.1†	Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.3 to Amendment No. 1 to the Registration Statement on Form S-1 filed on November 14, 2011).
10.2†	Employment Agreement between Matador Resources Company and David E. Lancaster (incorporated by reference to Exhibit 10.4 to Amendment No. 1 to the Registration Statement on Form S-1 filed on November 14, 2011).
10.3†	Employment Agreement between Matador Resources Company and Matthew Hairford (incorporated by reference to Exhibit 10.5 to Amendment No. 1 to the Registration Statement on Form S-1 filed on November 14, 2011).
10.4†	First Amendment to the Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.8 to Amendment No. 1 to the Registration Statement on Form S-1 filed on November 14, 2011).
10.5†	First Amendment to the Employment Agreement between Matador Resources Company and David E. Lancaster (incorporated by reference to Exhibit 10.9 to Amendment No. 1 to the Registration Statement on Form S-1 filed on November 14, 2011).
10.6†	First Amendment to the Employment Agreement between Matador Resources Company and Matthew Hairford (incorporated by reference to Exhibit 10.10 to Amendment No. 1 to the Registration Statement on Form S-1 filed on November 14, 2011).

Exhibit Number	Description
10.7†	Second Amendment to the Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.12 to Amendment No. 2 to the Registration Statement on Form S-1 filed on December 30, 2011).
10.8†	Second Amendment to the Employment Agreement between Matador Resources Company and David E. Lancaster (incorporated by reference to Exhibit 10.13 to Amendment No. 2 to the Registration Statement on Form S-1 filed on December 30, 2011).
10.9†	Second Amendment to the Employment Agreement between Matador Resources Company and Matthew Hairford (incorporated by reference to Exhibit 10.14 to Amendment No. 2 to the Registration Statement on Form S-1 filed on December 30, 2011).
10.10†	Form of Indemnification Agreement between Matador Resources Company and each of the directors and executive officers thereof (incorporated by reference to Exhibit 10.22 to Amendment No. 1 to the Registration Statement on Form S-1 filed on November 14, 2011).
10.11	Third Amended and Restated Credit Agreement, dated as of September 28, 2012, by and among MRC Energy Company, as Borrower, the Lending Entities from time to time parties thereto, as Lenders, and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on October 4, 2012).
10.12	Second Amended and Restated Pledge and Security Agreement, by and among MRC Energy Company, Longwood Gathering and Disposal Systems GP, Inc. and Royal Bank of Canada, as Administrative Agent, dated as of September 28, 2012 (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.13	Second Amended, Restated and Consolidated Unconditional Guaranty, by and among MRC Permian Company, MRC Rockies Company, Matador Production Company, Longwood Gathering and Disposal Systems GP, Inc., Longwood Gathering and Disposal Systems, LP, Matador Resources Company and Royal Bank of Canada, as Administrative Agent, dated as of September 28, 2012 (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.14	First Amendment to Third Amended and Restated Credit Agreement dated as of March 11, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.15	Second Amendment to Third Amended and Restated Credit Agreement dated as of June 4, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 6, 2013).
10.16	Third Amendment to Third Amended and Restated Credit Agreement, dated as of August 7, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
10.17	Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of March 12, 2014, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2013).

Exhibit Number	Description
10.18	Fifth Amendment to Third Amended and Restated Credit Agreement, dated as of September 5, 2014, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on September 8, 2014).
10.19	Sixth Amendment to Third Amended and Restated Credit Agreement, dated as of April 14, 2015, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on April 14, 2015).
10.20	Seventh Amendment to Third Amended and Restated Credit Agreement, dated as of October 16, 2015, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on October 21, 2015).
10.21	Eighth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2016, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on November 2, 2016).
10.22	Limited Consent and Ninth Amendment to Third Amended and Restated Credit Agreement, dated as of December 9, 2016, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on December 9, 2016).
10.23	Tenth Amendment to Third Amended and Restated Credit Agreement, dated as of April 28, 2017, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 4, 2017).
10.24†	Form of Employment Agreement between Matador Resources Company and Craig N. Adams (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2013).
10.25†	Form of Employment Agreement between Matador Resources Company and Van H. Singleton, II, effective February 5, 2015 (incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K for the year ended December 31, 2014).
10.26†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2014).
10.27†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K for the year ended December 31, 2015).
10.28†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2015).
10.29†	Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on June 11, 2015).
10.30†	Matador Resources Company Nonqualified Deferred Compensation Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.59 to the Annual Report on Form 10-K for the year ended December 31, 2015).

Exhibit Number	Description
10.31†	Form of Restricted Stock Unit Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.62 to the Annual Report on Form 10-K for the year ended December 31, 2016).
10.32†	Form of Restricted Stock Unit Award Agreement for deferred delivery relating to the Matador Resources Company 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.63 to the Annual Report on Form 10-K for the year ended December 31, 2016).
10.33†	Form of Letter Agreement between Matador Resources Company and certain directors modifying Restricted Stock Unit Award Agreements (incorporated by reference to Exhibit 10.64 to the Annual Report on Form 10-K for the year ended December 31, 2016).
10.34†	Form of Employment Agreement between Matador Resources Company and each of Billy E. Goodwin and G. Gregg Krug, effective February 19, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2017).
10.35†	Form of Restricted Stock Unit Award Agreement for Annual Grants with delayed delivery relating to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
10.36†	Amendment Number One to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.37†	Form of Restricted Stock Unit Award Agreement for director awards with deferred delivery under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.38†	Form of Nonqualified Stock Option Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.39†	Form of Nonqualified Stock Option Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.40†	Form of Restricted Stock Award Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.41†	Form of Restricted Stock Award Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017).
10.42†	First Amendment to the Employment Agreement between Matador Resources Company and Billy E. Goodwin (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2018).
10.43†	Amended and Restated Employment Agreement between Matador Resources Company and Bradley M. Robinson (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2018).

Exhibit Number	Description
10.44	Eleventh Amendment to Third Amended and Restated Credit Agreement, dated as of August 7, 2018, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on August 9, 2018).
10.45	Twelfth Amendment to Third Amended and Restated Credit Agreement, dated as of October 1, 2018, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on October 4, 2018).
10.46	Thirteenth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2018, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on November 1, 2018).
10.47†	Matador Resources Company Annual Cash Incentive Plan, effective as of January 1, 2019 (incorporated by reference to Exhibit 10.66 to the Annual Report on Form 10-K for the year ended December 31, 2018).
10.48†	Form of Phantom Unit Award Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.67 to the Annual Report on Form 10-K for the year ended December 31, 2018).
10.49†	Form of Performance Stock Unit Award Agreement for awards under the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.68 to the Annual Report on Form 10-K for the year ended December 31, 2018).
10.50†	Matador Resources Company 2019 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to the Registration Statement on Form S-8 filed on June 6, 2019).
10.51†	Form of Restricted Stock Unit Award Agreement for director awards under the Matador Resources Company 2019 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).
10.52†	Form of Restricted Stock Unit Award Agreement for director awards with deferred delivery under the Matador Resources Company 2019 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).
10.53†	First Amendment to the Employment Agreement between Matador Resources Company and G. Gregg Krug (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).
10.54†	First Amendment to the Amended and Restated Employment Agreement between Matador Resources Company and Bradley M. Robinson (incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).
10.55	Fourteenth Amendment to Third Amended and Restated Credit Agreement, dated as of February 27, 2020, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (filed herewith).
21.1	List of Subsidiaries of Matador Resources Company (filed herewith).

Exhibit Number	Description
23.1	Consent of KPMG LLP (filed herewith).
23.2	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).
101	The following financial information from Matador Resources Company's Annual Report on Form 10-K for the year ended December 31, 2019, formatted in Inline XBRL (Inline eXtensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Changes in Shareholders' Equity, (iv) the Consolidated Statements of Cash Flows and (v) the Notes to Consolidated Financial Statements (submitted electronically herewith).
104	Cover Page Interactive Data File, formatted in Inline XBRL (included as Exhibit 101).

† Indicates a management contract or compensatory plan or arrangement.

* Pursuant to Item 601(b)(2) of Regulation S-K, the Company agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

Signatures

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

MATADOR RESOURCES COMPANY

March 2, 2020

By: /s/ JOSEPH WM. FORAN
Joseph Wm. Foran
Chairman and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual 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/ JOSEPH WM. FORAN Joseph Wm. Foran	Chairman and Chief Executive Officer (Principal Executive Officer)	March 2, 2020
/s/ DAVID E. LANCASTER David E. Lancaster	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 2, 2020
/s/ ROBERT T. MACALIK Robert T. Macalik	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 2, 2020
/s/ REYNALD A. BARIBAULT Reynald A. Baribault	Director	March 2, 2020
/s/ R. GAINES BATY R. Gaines Baty	Director	March 2, 2020
/s/ CRAIG T. BURKERT Craig T. Burkert	Director	March 2, 2020
/s/ WILLIAM M. BYERLEY William M. Byerley	Director	March 2, 2020
/s/ MATTHEW P. CLIFTON Matthew P. Clifton	Director	March 2, 2020
/s/ MONIKA U. EHRMAN Monika U. Ehrman	Director	March 2, 2020
/s/ JULIA P. FORRESTER ROGERS Julia P. Forrester Rogers	Director	March 2, 2020
/s/ TIMOTHY E. PARKER Timothy E. Parker	Director	March 2, 2020
/s/ DAVID M. POSNER David M. Posner	Director	March 2, 2020
/s/ KENNETH L. STEWART Kenneth L. Stewart	Director	March 2, 2020

Glossary of Oil and Natural Gas Terms

The following is a description of the meanings of some of the oil and natural gas industry terms used in this Annual Report.

Batch drilling. The process by which multiple horizontal wells are drilled from a single pad. In batch drilling, the surface holes for each well are drilled first and then the production holes, including the horizontal laterals for each well, are drilled.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this Annual Report in reference to crude oil, other liquid hydrocarbons or salt water.

Bcf. One billion cubic feet of natural gas.

BOE. Barrels of oil equivalent, determined using the ratio of one Bbl of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

BOE/d. BOE per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The operations required to establish production of oil or natural gas from a wellbore, usually involving perforations, stimulation and/or installation of permanent equipment in the well, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reservoir.

Conventional reservoirs or resources. Natural gas or oil that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the natural gas or oil to readily flow to the wellbore.

Coring. The act of taking a core. A core is a solid column of rock, usually from two to four inches in diameter, taken as a sample of an underground formation. It is common practice to take cores from wells in the process of being drilled. A core bit is attached to the end of the drill pipe. The core bit then cuts a column of rock from the formation being penetrated. The core is then removed and tested for evidence of oil or natural gas, and its characteristics (porosity, permeability, etc.) are determined.

Developed acreage. The number of acres that are allocated or assignable to productive wells.

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

Differential. The difference between a particular oil or natural gas price and the applicable benchmark price, such as the NYMEX West Texas Intermediate oil price or the NYMEX Henry Hub natural gas price.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production-related expenses and taxes.

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Farmin or farmout. An agreement under which the owner of a working interest in an oil or natural gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farmin" while the interest transferred by the assignor is a "farmout."

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells in which a working interest is owned.

Held by production. An oil and natural gas property under lease in which the lease continues to be in force after the primary term of the lease in accordance with its terms as a result of production from the property.

Horizontal drilling or well. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation typically yields a horizontal well that has the ability to produce higher volumes than a vertical well drilled in the same formation. A horizontal well is designed to replace multiple vertical wells, resulting in lower capital expenditures for draining like acreage and limiting surface disruption.

Hydraulic fracturing. The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to prop the channel open, so that fluids or gases may more easily flow from the formation, through the fracture channel and into the wellbore. This technique may also be referred to as fracture stimulation.

Lateral length. Length of the completed portion of a horizontal well.

Liquids. Liquids, or natural gas liquids, are marketable liquid products including ethane, propane, butane, pentane and natural gasoline resulting from the further processing of liquefiable hydrocarbons separated from raw natural gas by a natural gas processing facility.

MBbl. One thousand barrels of crude oil, other liquid hydrocarbons or salt water.

MBOE. One thousand BOE.

Mcf. One thousand cubic feet of natural gas.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NGL. Natural gas liquids.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or wells.

Net revenue interest. The interest that defines the percentage of revenue that an owner of a well receives from the sale of oil, natural gas and/or natural gas liquids that are produced from the well.

NYMEX. New York Mercantile Exchange.

Overriding royalty interest. A fractional interest in the gross production of oil and natural gas under a lease, in addition to the usual royalties paid to the lessor, free of any expense for exploration, drilling, development, operating, marketing and other costs incident to the production and sale of oil and natural gas produced from the lease. It is an interest carved out of the lessee's working interest, as distinguished from the lessor's reserved royalty interest.

Pad. The surface constructed to accommodate the drilling, completion and production operations of an oil or natural gas well.

Pad drilling. The process by which multiple horizontal wells are drilled from a single pad. In pad drilling, each well on the pad is drilled to total depth before the next well is initiated.

Permeability. A reference to the ability of oil and/or natural gas to flow through a reservoir.

Petrophysical analysis. The interpretation of well log measurements, obtained from a string of electronic tools inserted into the borehole, and from core measurements, in which rock samples are retrieved from the subsurface, then combining these measurements with other relevant geological and geophysical information to describe the reservoir rock properties.

Play. A set of known or postulated oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, migration pathways, timing, trapping mechanism and hydrocarbon type.

Possible reserves. Additional reserves that are less certain to be recognized than probable reserves.

Probable reserves. Additional reserves that are less certain to be recognized than proved reserves but which, in sum with proved reserves, are as likely as not to be recovered.

Producing well, or productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the well's production exceed production-related expenses and taxes.

Properties. Natural gas and oil wells, production and related equipment and facilities and oil, natural gas, or other mineral fee, leasehold and related interests.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and preliminary economic analysis using reasonably anticipated prices and costs, is considered to have potential for the discovery of commercial hydrocarbons.

Proved developed non-producing. Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending installation of surface equipment or gathering facilities, or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved developed but non-producing reserves.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

Proved reserves. Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. Completing in the same wellbore to reach a new reservoir after production from the original reservoir has been abandoned.

Repeatability. The potential ability to drill multiple wells within a prospect or trend.

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

Royalty interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (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.

2-D seismic. The method by which a cross-section of the earth's subsurface is created through the interpretation of reflection seismic data collected along a single source profile.

3-D seismic. The method by which a three-dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do 2-D seismic surveys and contribute significantly to field appraisal, exploitation and production.

Spud. The act of beginning to drill an oil or natural gas well.

Throughput. The volume of product transported or passing through a pipeline, plant or other facility.

Trend. A region of oil and/or natural gas production, the geographic limits of which have not been fully defined, having geological characteristics that have been ascertained through supporting geological, geophysical or other data to contain the potential for oil and/or natural gas reserves in a particular formation or series of formations.

Unconventional resource play. A set of known or postulated oil and or natural gas resources or reserves warranting further exploration which are extracted from (i) low-permeability sandstone and shale formations and (ii) coalbed methane. These plays require the application of advanced technology to extract the oil and natural gas resources.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage is usually considered to be all acreage that is not allocated or assignable to productive wells.

Unproved and unevaluated properties. Properties where no drilling or other actions have been undertaken that permit such properties to be classified as proved and to which no proved reserves have been assigned.

Vertical well. A hole drilled vertically into the earth from which oil, natural gas or water flows or is pumped.

Visualization. An exploration technique in which the size and shape of subsurface features are mapped and analyzed based upon information derived from well logs, seismic data and other well information.

Volumetric reserve analysis. A technique used to estimate the amount of recoverable oil and natural gas. It involves calculating the volume of reservoir rock and adjusting that volume for rock porosity, hydrocarbon saturation, formation volume factor and recovery factor.

Walking rig. A drilling rig that is capable of moving from one drilling location to another a short distance away using a series of hydraulic "feet" built into the substructure of the rig.

Wellbore. The hole made by a well.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Consolidated Financial Statements

MATADOR RESOURCES COMPANY AND SUBSIDIARIES
December 31, 2019, 2018 and 2017

Contents *Page*

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Matador Resources Company:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Matador Resources Company and subsidiaries (the Company) as of December 31, 2019 and 2018, the related consolidated statements of operations, changes in shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 2, 2020 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of Accounting Standards Update 2016-02, *Leases (Topic 842)*, and related amendments.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the 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 wells as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgment. The communication of a critical audit matter 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Assessment of the impact of estimated oil and natural gas reserves related to evaluated oil and natural gas properties on depletion expense and the ceiling test calculation

As discussed in Note 2 to the consolidated financial statements, the Company uses the full-cost method of accounting for its investments in oil and natural gas properties and amortizes capitalized costs of oil and natural gas properties using the unit-of-production method based on production and estimates of proved reserves quantities. For the year ended December 31, 2019, the Company recorded depletion expense of evaluated oil and natural gas properties of $330.7 million. Additionally, as discussed in Note 3 to the consolidated financial statements, the Company recorded $4.6 billion of gross evaluated oil and natural gas properties as of December 31, 2019. The Company is required to perform a ceiling test calculation on a quarterly basis and the applicable ceiling is equal to the sum of (1) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus (2) unproved and unevaluated property costs not being amortized, plus (3) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less (4) any income tax effects related to the properties involved. Estimates of economically recoverable oil and natural gas reserves depend upon a number of factors and assumptions, including quantities of oil and natural gas that are ultimately recovered, the timing of the recovery of oil and natural gas reserves, the operating costs incurred, the amount of future development expenditures, and the price received for the production. The Company's internal reserves engineers prepare an estimate of the proved oil and natural gas reserves, and the Company engages external reserves engineers to independently evaluate the proved oil and natural gas reserves estimated by the Company.

We identified the assessment of the impact of estimated oil and natural gas reserves related to evaluated oil and natural gas properties on both depletion expense and the ceiling test calculation as a critical audit matter. There is a high degree of subjectivity in evaluating the estimate of proved oil and natural gas reserves, as auditor judgment was required to evaluate the assumptions used by the Company related to forecasted production, development costs, operating costs, and forecasted oil and natural gas prices inclusive of market differentials.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's depletion and ceiling test processes, including controls related to the assumptions used to estimate proved reserves used in the respective calculations. We assessed the competence, capabilities, and objectivity of the Company's internal reserves engineers, who estimated the proved reserves, and the external reserves engineers engaged by the Company. We assessed the methodology used by the Company to estimate the reserves for consistency with industry and regulatory standards. We also compared the pricing assumptions, including price differentials, used in the reserves engineers' estimate of the proved reserves to publicly available oil and natural gas pricing data. We evaluated assumptions used in the reserves engineers' estimate regarding future operating and development costs based on historical information. In addition, we compared the forecasted production volumes assumption used by the Company in the current period to historical production and we compared the Company's historical production forecasts to actual production volumes to assess the Company's ability to accurately forecast. We read the findings of the Company's external reserves engineers in connection with our evaluation of the Company's reserves estimates. We analyzed the depletion expense calculation for compliance with industry and regulatory standards, and recalculated it. We also analyzed the ceiling test impairment calculation for compliance with industry and regulatory standards. In addition, we performed an independent calculation of the ceiling test impairment calculation and compared our results with the Company's results.

/s/ KPMG LLP

We have served as the Company's auditor since 2014.

Dallas, Texas
March 2, 2020

Consolidated Balance Sheets

Matador Resources Company and Subsidiaries

	December 31,	
	2019	2018
(In thousands, except par value and share data)		
ASSETS		
Current assets		
Cash	$ 40,024	$ 64,545
Restricted cash	25,104	19,439
Accounts receivable		
Oil and natural gas revenues	95,228	68,161
Joint interest billings	67,546	61,831
Other	26,639	16,159
Derivative instruments	—	49,929
Lease and well equipment inventory	10,744	17,564
Prepaid expenses and other current assets	13,207	8,057
Total current assets	278,492	305,685
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	4,557,265	3,780,236
Unproved and unevaluated	1,126,992	1,199,511
Midstream properties	643,903	428,025
Other property and equipment	27,021	22,041
Less accumulated depletion, depreciation and amortization	(2,655,586)	(2,306,949)
Net property and equipment	3,699,595	3,122,864
Other assets		
Deferred income taxes	—	20,457
Other long-term assets	91,589	6,512
Total other assets	91,589	26,969
Total assets	$ 4,069,676	$ 3,455,518
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 25,230	$ 66,970
Accrued liabilities	200,695	170,855
Royalties payable	85,193	64,776
Amounts due to affiliates	19,606	13,052
Derivative instruments	1,897	—
Advances from joint interest owners	14,837	10,968
Amounts due to joint ventures	486	2,373
Other current liabilities	51,828	1,028
Total current liabilities	399,772	330,022
Long-term liabilities		
Borrowings under Credit Agreement	255,000	40,000
Borrowings under San Mateo Credit Facility	288,000	220,000
Senior unsecured notes payable	1,039,416	1,037,837
Asset retirement obligations	35,592	29,736
Derivative instruments	1,984	83
Deferred income taxes	37,329	13,221
Other long-term liabilities	43,131	4,962
Total long-term liabilities	1,700,452	1,345,839
Commitments and contingencies (Note 14)		
Shareholders' equity		
Common stock — $0.01 par value, 160,000,000 shares authorized; 116,644,246 and 116,374,503 shares issued; and 116,642,899 and 116,353,590 shares outstanding, respectively	1,166	1,164
Additional paid-in capital	1,981,014	1,924,408
Accumulated deficit	(148,500)	(236,277)
Treasury stock, at cost, 1,347 and 20,913 shares, respectively	(26)	(415)
Total Matador Resources Company shareholders' equity	1,833,654	1,688,880
Non-controlling interest in subsidiaries	135,798	90,777
Total shareholders' equity	1,969,452	1,779,657
Total liabilities and shareholders' equity	$ 4,069,676	$ 3,455,518

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Operations

Matador Resources Company and Subsidiaries

	Year Ended December 31,		
	2019	2018	2017
(In thousands, except per share data)			
Revenues			
Oil and natural gas revenues	$892,325	$800,700	$528,684
Third-party midstream services revenues	59,110	21,920	10,198
Sales of purchased natural gas	74,769	7,071	—
Lease bonus - mineral acreage	1,711	2,489	—
Realized gain (loss) on derivatives	9,482	2,334	(4,321)
Unrealized (loss) gain on derivatives	(53,727)	65,085	9,715
Total revenues	983,670	899,599	544,276
Expenses			
Production taxes, transportation and processing	92,273	76,138	58,275
Lease operating	117,305	92,966	67,313
Plant and other midstream services operating	36,798	24,609	13,039
Purchased natural gas	69,398	6,635	—
Depletion, depreciation and amortization	350,540	265,142	177,502
Accretion of asset retirement obligations	1,822	1,530	1,290
General and administrative	80,054	69,308	66,016
Total expenses	748,190	536,328	383,435
Operating income	235,480	363,271	160,841
Other income (expense)			
Net (loss) gain on asset sales and inventory impairment	(967)	(196)	23
Interest expense	(73,873)	(41,327)	(34,565)
Prepayment premium on extinguishment of debt	—	(31,226)	—
Other (expense) income	(2,126)	1,551	3,551
Total other expense	(76,966)	(71,198)	(30,991)
Income before income taxes	158,514	292,073	129,850
Income tax provision (benefit)			
Current	—	(455)	(8,157)
Deferred	35,532	(7,236)	—
Total income tax provision (benefit)	35,532	(7,691)	(8,157)
Net income	122,982	299,764	138,007
Net income attributable to non-controlling interest in subsidiaries	(35,205)	(25,557)	(12,140)
Net income attributable to Matador Resources Company shareholders	$ 87,777	$274,207	$125,867
Earnings per common share			
Basic	$ 0.75	$ 2.41	$ 1.23
Diluted	$ 0.75	$ 2.41	$ 1.23
Weighted average common shares outstanding			
Basic	116,555	113,580	102,029
Diluted	117,063	113,691	102,543

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

Matador Resources Company and Subsidiaries

	For the Years Ended December 31, 2019, 2018 and 2017								
	Common Stock		Additional paid-in capital	Accumulated deficit	Treasury Stock		Total shareholders' equity attributable to Matador Resources Company	Non-controlling interest in subsidiaries	Total shareholders' equity
	Shares	Amount			Shares	Amount			
(In thousands)									
Balance at January 1, 2017	99,519	$ 995	$1,325,481	$(636,351)	6	$ —	$ 690,125	$ 1,320	$ 691,445
Issuance of common stock pursuant to employee stock compensation plan	530	5	(5)	—	—	—	—	—	—
Issuance of common stock pursuant to directors' and advisors' compensation plan	77	1	(1)	—	—	—	—	—	—
Issuance of common stock pursuant to public offering	8,000	80	208,640	—	—	—	208,720	—	208,720
Cost to issue equity	—	—	(280)	—	—	—	(280)	—	(280)
Stock-based compensation expense related to equity-based awards including amounts capitalized	—	—	19,594	—	—	—	19,594	—	19,594
Stock options exercised, net of options forfeited in net share settlements	514	5	(1,189)	—	—	—	(1,184)	—	(1,184)
Restricted stock forfeited	—	—	—	—	123	(1,658)	(1,658)	—	(1,658)
Purchase of non-controlling interest of less-than-wholly-owned subsidiary	—	—	(1,250)	—	—	—	(1,250)	(1,403)	(2,653)
Contributions related to formation of San Mateo I (see Note 6)	—	—	116,622	—	—	—	116,622	54,878	171,500
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	44,100	44,100
Distributions to non-controlling interest owners of less-than wholly-owned subsidiaries	—	—	—	—	—	—	—	(10,045)	(10,045)
Cancellation of treasury stock	(126)	(1)	(1,588)	—	(126)	1,589	—	—	—
Current period net income	—	—	—	125,867	—	—	125,867	12,140	138,007
Balance at December 31, 2017	108,514	$1,085	$1,666,024	$(510,484)	3	$ (69)	$1,156,556	$ 100,990	$1,257,546
Issuance of common stock pursuant to employee stock compensation plan	759	8	(8)	—	—	—	—	—	—
Issuance of common stock pursuant to directors' and advisors' compensation plan	81	1	(1)	—	—	—	—	—	—
Issuance of common stock pursuant to public offering	7,000	70	226,542	—	—	—	226,612	—	226,612
Cost to issue equity	—	—	(204)	—	—	—	(204)	—	(204)
Stock-based compensation expense related to equity-based awards including amounts capitalized	—	—	22,660	—	—	—	22,660	—	22,660
Stock options exercised, net of options forfeited in net share settlements	179	2	(1,269)	—	—	—	(1,267)	—	(1,267)
Restricted stock forfeited	—	—	—	—	176	(4,384)	(4,384)	—	(4,384)
Contributions related to formation of San Mateo I (see Note 6)	—	—	14,700	—	—	—	14,700	—	14,700
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	85,750	85,750
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	(121,520)	(121,520)
Cancellation of treasury stock	(158)	(2)	(4,036)	—	(158)	4,038	—	—	—
Current period net income	—	—	—	274,207	—	—	274,207	25,557	299,764
Balance at December 31, 2018	116,375	$1,164	$1,924,408	$(236,277)	21	$ (415)	$1,688,880	$ 90,777	$1,779,657
Issuance of common stock pursuant to employee stock compensation plan	240	2	(2)	—	—	—	—	—	—
Issuance of common stock pursuant to directors' and advisors' compensation plan	50	—	—	—	—	—	—	—	—
Stock-based compensation expense related to equity-based awards including amounts capitalized	—	—	23,396	—	—	—	23,396	—	23,396
Stock options exercised, net of options forfeited in net share settlements	220	2	3,298	—	—	—	3,300	—	3,300
Liability-based stock option awards settled	1	—	11	—	—	—	11	—	11
Restricted stock forfeited	—	—	—	—	222	(3,691)	(3,691)	—	(3,691)
Contribution related to formation of San Mateo I, net of tax of $3.1 million (See Note 6)	—	—	11,613	—	—	—	11,613	—	11,613
Contribution of property related to formation of San Mateo II (See Note 6)	—	—	(506)	—	—	—	(506)	506	—
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries, net of tax of $5.9 million (See Note 6)	—	—	22,874	—	—	—	22,874	48,510	71,384
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	(39,200)	(39,200)
Cancellation of treasury stock	(242)	(2)	(4,078)	—	(242)	4,080	—	—	—
Current period net income	—	—	—	87,777	—	—	87,777	35,205	122,982
Balance at December 31, 2019	116,644	$1,166	$1,981,014	$(148,500)	1	$ (26)	$1,833,654	$ 135,798	$1,969,452

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows

Matador Resources Company and Subsidiaries

	Year Ended December 31,		
(In thousands)	2019	2018	2017
Operating activities			
Net income	$ 122,982	$ 299,764	$ 138,007
Adjustments to reconcile net income to net cash provided by operating activities			
Unrealized loss (gain) on derivatives	53,727	(65,085)	(9,715)
Depletion, depreciation and amortization	350,540	265,142	177,502
Accretion of asset retirement obligations	1,822	1,530	1,290
Stock-based compensation expense	18,505	17,200	16,654
Prepayment premium on extinguishment of debt	—	31,226	—
Deferred income tax provision (benefit)	35,532	(7,236)	—
Amortization of debt issuance cost	2,484	1,357	468
Net loss (gain) on asset sales and inventory impairment	967	196	(23)
Changes in operating assets and liabilities			
Accounts receivable	(43,261)	(4,934)	(82,549)
Lease and well equipment inventory	4,777	(12,176)	(3,623)
Prepaid expenses and other current assets	(4,844)	(1,770)	(2,960)
Other long-term assets	678	3,418	(6,425)
Accounts payable, accrued liabilities and other current liabilities	(19,004)	68,647	33,559
Royalties payable	20,417	3,418	37,370
Advances from joint interest owners	3,869	8,179	1,089
Other long-term liabilities	2,851	(353)	(1,519)
Net cash provided by operating activities	552,042	608,523	299,125
Investing activities			
Oil and natural gas properties capital expenditures	(730,161)	(1,357,802)	(699,445)
Midstream capital expenditures	(192,035)	(163,222)	(115,128)
Expenditures for other property and equipment	(3,701)	(2,562)	(5,688)
Proceeds from sale of assets	21,921	8,333	977
Net cash used in investing activities	(903,976)	(1,515,253)	(819,284)
Financing activities			
Repayments of borrowings	(35,000)	(370,000)	—
Borrowings under Credit Agreement	250,000	410,000	—
Borrowings under San Mateo Credit Facility	68,000	220,000	—
Cost to enter into or amend credit facilities	(1,443)	(3,077)	—
Proceeds from issuance of senior unsecured notes	—	1,051,500	—
Cost to issue senior unsecured notes	—	(14,098)	—
Purchase of senior unsecured notes	—	(605,780)	—
Proceeds from issuance of common stock	—	226,612	208,720
Cost to issue equity	—	(204)	(280)
Proceeds from stock options exercised	3,300	815	2,920
Contributions related to formation of San Mateo I	14,700	14,700	171,500
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	77,330	85,750	44,100
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	(39,200)	(121,520)	(10,045)
Taxes paid related to net share settlement of stock-based compensation	(3,691)	(6,466)	(5,763)
Purchase of non-controlling interest of less-than-wholly-owned subsidiary	—	—	(2,653)
Cash paid under financing lease obligations	(918)	—	—
Net cash provided by financing activities	333,078	888,232	408,499
Decrease in cash and restricted cash	(18,856)	(18,498)	(111,660)
Cash and restricted cash at beginning of year	83,984	102,482	214,142
Cash and restricted cash at end of year	$ 65,128	$ 83,984	$ 102,482

Supplemental disclosures of cash flow information (Note 15)

The accompanying notes are an integral part of these consolidated financial statements.

MATADOR RESOURCES COMPANY AND SUBSIDIARIES
December 31, 2019, 2018 and 2017

NOTE 1 — NATURE OF OPERATIONS

Matador Resources Company, a Texas corporation ("Matador" and, collectively with its subsidiaries, the "Company"), is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. The Company's current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company also operates in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana. Additionally, the Company conducts midstream operations, primarily through its midstream joint ventures, San Mateo Midstream, LLC ("San Mateo I") and San Mateo Midstream II, LLC ("San Mateo II" and, together with San Mateo I, "San Mateo"), in support of the Company's exploration, development and production operations and provides natural gas processing, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements include the accounts of Matador and its wholly-owned and majority-owned subsidiaries. These consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP"). Accordingly, the Company consolidates certain subsidiaries and joint ventures that are less-than-wholly-owned and are not involved in oil and natural gas exploration, including San Mateo, and the net income and equity attributable to the non-controlling interest in these subsidiaries have been reported separately as required by Accounting Standards Codification ("ASC"), *Consolidation (Topic 810)*. The Company proportionately consolidates certain joint ventures that are less-than-wholly-owned and are involved in oil and natural gas exploration. All intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements, purchase price allocations and the reported amounts of revenues and expenses during the reporting period. The Company's consolidated financial statements are based on a number of significant estimates, including oil and natural gas revenues, accrued assets and liabilities, stock-based compensation, valuation of derivative instruments, deferred tax assets and liabilities, purchase price allocations and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates of asset retirement obligations and certain tax accruals. The Company's oil and natural gas reserves estimates, which are inherently imprecise and based upon many factors that are beyond the Company's control, including oil and natural gas prices, are prepared by the Company's engineering staff in accordance with guidelines established by the Securities and Exchange Commission ("SEC") and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Change in Accounting Principles

Leases. During the first quarter of 2019, the Company adopted Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842)* and the amendments provided for in ASU 2018-11, *Leases (Topic 842)*, which require the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous U.S. GAAP using a modified retrospective approach. The modified retrospective approach includes a number of optional practical expedients that the Company chose to apply. These practical expedients relate to (i) the identification and classification of leases that commenced before the effective date, (ii) the treatment of initial direct costs for leases that commenced before the effective date, (iii) the ability to use hindsight in evaluating lessee options to extend or terminate a lease or to purchase the underlying asset and (iv) the ability to initially apply the new lease standard at the adoption date. During the first quarter of 2019, the Company also adopted ASU 2018-01, *Leases (Topic 842)*, which is a land easement practical expedient, and, as a result, the Company began evaluating land easements that are entered into or modified after December 31, 2018. See Note 4 for additional disclosures related to leases.

The adoption of these ASUs resulted in the Company recording in the consolidated balance sheet beginning January 1, 2019 certain of the Company's compressor leases, drilling rig leases and office leases, which were previously considered operating leases and not reported on the Company's consolidated balance sheets. As such, upon adoption, the Company recorded (i) long-term right of use assets of $62.3 million, which are included in "Other assets" and "Other property and equipment," and (ii) net right of use liabilities of $62.3 million, which are included in "Other current liabilities" and "Other long-term liabilities." There was no cumulative-effect adjustment to the opening balance of accumulated deficit as a result of the adoption of these ASUs.

Stock Compensation. During the first quarter of 2019, the Company also adopted ASU 2018-07, *Compensation - Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting*, which extends the scope of Topic 718 to include share-based payment transactions related to the acquisition of goods and services from nonemployees. Previously, the Company accounted for stock-based awards to special advisors and contractors under ASC 505-50 as liability instruments, and the fair value of the awards was recalculated each reporting period. Upon adoption, all such awards are now measured at fair value on the grant date, and the resulting expense is recognized on a straight-line basis over the awards' vesting periods. The transitional guidance requires entities to remeasure all unvested awards that are being accounted for under ASC 505-50 as liability instruments as of the beginning of the year in which this ASU is adopted. Adoption of this ASU did not have a material impact on the Company's consolidated financial statements.

Restricted Cash

Restricted cash represents a portion of the cash associated with the Company's less-than-wholly-owned subsidiaries, primarily San Mateo. By contractual agreement, the cash in the accounts held by the Company's less-than-wholly-owned subsidiaries is not to be commingled with other Company cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Accounts Receivable

The Company sells its operated oil, natural gas and natural gas liquid ("NGL") production to various purchasers (See "Revenues" below.) In addition, the Company may participate with industry partners in the drilling, completion and operation of oil and natural gas wells. Substantially all of the Company's accounts receivable are due from either purchasers of oil, natural gas and NGLs or participants in oil and natural gas wells for which the Company serves as the operator. Accounts receivable are due within 30 to 60 days of the production date and 30 days of the billing date and are stated at amounts due from purchasers and industry partners. Amounts are considered past due if they have been outstanding for 60 days or more. No interest is typically charged on past due amounts.

The Company reviews its need for an allowance for doubtful accounts on a periodic basis and determines the allowance, if any, by considering the length of time past due, previous loss history, future net revenues of the debtor's ownership interest in oil and natural gas properties operated by the Company and the debtor's ability to pay its obligations, among other things. The Company has no allowance for doubtful accounts related to its accounts receivable for any reporting period presented.

For the year ended December 31, 2019, two significant purchasers accounted for 67% of the Company's total oil, natural gas and NGL revenues: Plains Marketing, L.P. (53%) and BP America Production Company (14%). For the year ended December 31, 2018, four significant purchasers accounted for 60% of the Company's total oil, natural gas and NGL revenues: Plains Marketing, L.P. (19%), BP America Production Company (15%), Occidental Energy Marketing, Inc. (14%) and Western Refining Crude Oil (12%). For the year ended December 31, 2017, four significant purchasers accounted for 60% of the Company's total oil, natural gas and NGL revenues: Occidental Energy Marketing, Inc. (23%), Plains Marketing, L.P. (14%), Shell Trading (US) Company (12%) and Western Refining Crude Oil (11%). If the Company lost one or more of these significant purchasers and were unable to sell its production to other purchasers on terms it considers acceptable, it could materially and adversely affect the Company's business, financial condition, results of operations and cash flows. At December 31, 2019, 2018 and 2017, approximately 31%, 34% and 43%, respectively, of the Company's accounts receivable, including joint interest billings, related to these purchasers.

Lease and Well Equipment Inventory

Lease and well equipment inventory is stated at the lower of cost or market and consists entirely of materials or equipment scheduled for use in future well or midstream operations.

Oil and Natural Gas Properties

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company's activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to acquisition, exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized $31.1 million, $28.3 million and $23.1 million of its general and administrative costs into oil and natural gas properties in 2019, 2018 and 2017, respectively. The Company capitalized $7.6 million, $8.8 million and $7.3 million of its interest expense into oil and natural gas properties for the years ended December 31, 2019, 2018 and 2017, respectively.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved reserves quantities. For the years ended December 31, 2019, 2018 and 2017, the Company recorded depletion expense of $330.7 million, $251.8 million and $170.3 million, respectively. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the amortization base. Exploratory dry holes are included in the amortization base immediately upon determination that the well is not productive.

Sales of oil and natural gas properties are accounted for as adjustments to net capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between net capitalized costs and proved reserves of oil and natural gas. All costs related to production activities and maintenance and repairs are expensed as incurred. Significant workovers that increase the properties' reserves are capitalized.

Ceiling Test

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center "ceiling." The cost center ceiling is defined as the sum of:

(a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus

(b) unproved and unevaluated property costs not being amortized, plus

(c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less

(d) any income tax effects related to the properties involved.

Any excess of the Company's net capitalized costs above the cost center ceiling as described above is charged to operations as a full-cost ceiling impairment. The Company's derivative instruments are not considered in the ceiling test computations as the Company does not designate these instruments as hedge instruments for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent upon the quantities of proved reserves, the estimation of which requires substantial judgment. The associated commodity prices and the applicable discount rate used in these estimates are in accordance with guidelines established by the SEC. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost changes in future periods except by contractual arrangements. Future net revenues are calculated using prices that represent the arithmetic averages of the first-day-of-the-month oil and natural gas prices for the previous 12-month period, and a 10% discount factor is used to determine the present value of future net revenues. For the period from January through December 2019, these average oil and natural gas prices were $52.19 per Bbl and $2.58 per MMBtu, respectively. For the period from January through December 2018, these average oil and natural gas prices were $62.04 per Bbl and $3.10 per MMBtu, respectively. For the period from January through December 2017, these average oil and natural gas prices were $47.79 per Bbl and $2.98 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were further adjusted by property for quality, transportation and marketing fees and regional price differentials, and the average natural gas prices were further adjusted by property for energy content, transportation and marketing fees and regional price differentials.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

During the years ended December 31, 2019, 2018 and 2017, the Company's full-cost ceiling exceeded the net capitalized costs less related deferred income taxes. As a result, the Company recorded no impairment to its net capitalized costs during the years ended December 31, 2019, 2018 and 2017.

As a non-cash item, the full-cost ceiling impairment impacts the accumulated depletion and the net carrying value of the Company's assets on its consolidated balance sheets, as well as the corresponding shareholders' equity, but it has no impact on the Company's net cash flows as reported. Changes in oil and natural gas production rates, oil and natural gas prices, reserves estimates, future development costs and other factors will determine the Company's actual ceiling test computation and impairment analyses in future periods.

Midstream Properties and Other Property and Equipment

Midstream properties and other property and equipment are recorded at historical cost and include midstream equipment and facilities, including the Company's pipelines, processing facilities and salt water disposal systems, and corporate assets, including furniture, fixtures, equipment, land and leasehold improvements. Midstream equipment and facilities are depreciated over a 30-year useful life using the straight-line, mid-month convention method. Leasehold improvements are depreciated over the lesser of their useful lives or the term of the lease. Software, furniture, fixtures and other equipment are depreciated over their useful life (five to 30 years) using the straight-line method. The Company capitalized $1.8 million and $1.6 million of general and administrative costs into midstream properties in 2019 and 2018, respectively. The Company did not capitalize any general and administrative costs into midstream properties in 2017. The Company capitalized $0.9 million of interest expense into midstream properties for the year ended December 31, 2019. The Company did not capitalize any interest expense into midstream properties for the years ended December 31, 2018 and 2017. Maintenance and repair costs that do not extend the useful life of the property or equipment are expensed as incurred. See Note 3 for a detail of midstream properties and other property and equipment.

Gains and losses associated with the disposition of midstream properties and other property and equipment are recognized as a component of other income (expense) in the consolidated statements of operations.

Asset Retirement Obligations

The Company recognizes the fair value of an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The asset retirement obligation is recorded as a liability at its estimated present value, with an offsetting increase recognized in oil and natural gas properties, midstream properties or other property and equipment on the consolidated balance sheets. Periodic accretion of the discounted value of the estimated liability is recorded as an expense in the consolidated statements of operations.

Derivative Financial Instruments

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil, natural gas and NGL prices. The Company's derivative financial instruments are recorded on the consolidated balance sheets as either an asset or a liability measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments, and as a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statements of operations. The fair value of the Company's derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Realized gains and losses from the settlement of derivative financial instruments and

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

unrealized gains and unrealized losses from valuation changes in the remaining unsettled derivative financial instruments are reported as a component of revenues in the consolidated statements of operations. See Note 12 for additional information about the Company's derivative instruments.

Revenues

The Company enters into contracts with customers to sell its oil and natural gas production. Revenue from these contracts is recognized in accordance with the five-step revenue recognition model prescribed in ASC 606, *Revenue from Contracts with Customers (Topic 606)*. Specifically, revenue is recognized when the Company's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights. Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Company expects to receive in accordance with the price specified in the contract. Consideration under oil and natural gas marketing contracts is typically received from the purchaser one to two months after production.

The majority of the Company's oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the oil has been transferred to the purchaser. The majority of the oil produced is sold under contracts using market-based pricing, which price is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred at or after the transfer of control of the oil, the differentials are included in oil revenues on the statements of operations, as they represent part of the transaction price of the contract. If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in production taxes, transportation and processing expenses on the Company's consolidated statements of operations, as they represent payment for services performed outside of the contract with the customer.

The Company's natural gas is sold at the lease location, at the inlet or outlet of a natural gas processing plant or at an interconnect near a marketing hub following transportation from a processing plant. The majority of the Company's natural gas is sold under fee-based contracts. When the natural gas is sold at the lease, the purchaser gathers the natural gas via pipeline to natural gas processing plants where, if necessary, NGLs are extracted. The NGLs and remaining residue gas are then sold by the purchaser, or if the Company elects to take in-kind the natural gas or the NGLs, the Company sells the natural gas or the NGLs to a third party. Under the fee-based contracts, the Company receives NGL and residue gas value, less the fee component, or is invoiced the fee component. To the extent control of the natural gas transfers upstream of the gathering and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those services, revenue is recognized on a gross basis, and the related costs are included in production taxes, transportation and processing expenses on the Company's consolidated statements of operations.

The Company recognizes midstream services revenues at the time services have been rendered and the price is fixed and determinable. Third-party midstream services revenues are those revenues from midstream operations related to third parties, including working interest owners in the Company's operated wells. All midstream services revenues related to the Company's working interest are eliminated in consolidation. Since the Company has a right to payment from its customers in amounts that correspond directly to the value that the customer receives from the performance completed on each contract, the Company applies the practical expedient in ASC 606 that allows recognition of revenue in the amount for which there is a right to invoice the customer without estimating a transaction price for each contract and allocating that transaction price to the performance obligations within each contract.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

The Company periodically enters into natural gas purchase transactions with third parties whereby the Company processes the third party's natural gas at San Mateo's Black River cryogenic natural gas processing plant in Eddy County, New Mexico (the "Black River Processing Plant") and then purchases, and subsequently sells, the residue gas and NGLs to other purchasers. Revenues and expenses from these transactions are presented on a gross basis on the Company's consolidated statements of operations as the Company acts as a principal in the transactions by assuming the risk and rewards of ownership, including credit risk, of the natural gas purchased and by assuming the responsibility to deliver and process the natural gas volumes to be sold.

From time to time, the Company, as an owner of mineral interests, may enter into or extend a lease to a third-party lessee to develop the oil and natural gas attributable to certain of its mineral interests in return for a specified payment or lease bonus. In those instances, revenue is recognized in the period when the lease is signed and the Company has no further obligation to the lessee. The Company records these payments as "Lease bonus - mineral acreage" revenues on its consolidated statements of operations.

The following table summarizes the Company's total revenues and revenues from contracts with customers on a disaggregated basis for the years ended December 31, 2019 and 2018 (in thousands).

	Year Ended December 31,	
	2019	2018
Revenues from contracts with customers	$1,026,204	$829,691
Lease bonus - mineral acreage	1,711	2,489
Realized gain on derivatives	9,482	2,334
Unrealized (loss) gain on derivatives	(53,727)	65,085
Total revenues	$ 983,670	$899,599

	Year Ended December 31,	
	2019	2018
Oil revenues	$ 759,811	$635,554
Natural gas revenues	132,514	165,146
Third-party midstream services revenues	59,110	21,920
Sales of purchased natural gas	74,769	7,071
Total revenues from contracts with customers	$1,026,204	$829,691

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient in accordance with ASC 606. The expedient, as described in ASC 606-10-50-14(a), applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Stock-Based Compensation

The Company may grant equity-based and liability-based common stock, stock options, restricted stock, restricted stock units, performance stock units and other awards permitted under any long-term incentive plan of the Company then in effect to members of its Board of Directors and certain employees, contractors and advisors. All equity-based awards are measured at fair value on the date of grant and are recognized on a straight-line basis over the awards' vesting periods as either a component of general and administrative expenses in the consolidated

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

statements of operations or capitalized in accordance with the Company's policy on capitalizing general and administrative expenses for employees involved in acquisition, exploration and development activities. Awards that are expected to be settled in cash are liability-based awards, which are measured at fair value at each reporting date and are recognized on a straight-line basis over the awards' vesting periods either as a component of general and administrative expenses in the consolidated statements of operations or capitalized in accordance with the Company's policy on capitalizing general and administrative expenses for employees involved in acquisition, exploration and development activities. The Company accounts for all outstanding stock options granted under the Company's 2003 Stock and Incentive Plan (the "2003 Plan") as liability instruments as a result of the Company purchasing shares from certain of its employees to assist them in the exercise of outstanding options. As the stock options accounted for as liability-based awards are fully vested, changes in the fair value of the awards are recognized until the awards are settled as a component of general and administrative expenses in the consolidated statements of operations or capitalized in accordance with the Company's policy on capitalizing general and administrative expenses for employees involved in acquisition, exploration and development activities. All such stock options that were outstanding as of December 31, 2019 were settled in the first quarter of 2020.

The Company uses the Black Scholes Merton option pricing model to measure the fair value of stock options and the Monte Carlo simulation method to measure the fair value of performance units. The closing price of Matador's common stock on the grant date is used to measure the fair value of restricted stock and restricted stock unit awards granted under the 2003 Plan and the 2012 Long-Term Incentive Plan (as subsequently amended and restated, the "2012 Incentive Plan"), while the closing price of Matador's common stock on the trading day prior to the grant date is used to measure the fair value of restricted stock and restricted stock unit awards granted under the 2019 Long-Term Incentive Plan (the "2019 Incentive Plan").

The Company's consolidated statements of operations for the years ended December 31, 2019, 2018 and 2017 include a stock-based compensation (non-cash) expense of $18.5 million, $17.2 million and $16.7 million, respectively. This stock-based compensation expense includes common stock issuances and restricted stock units expense totaling $1.4 million, $1.6 million and $3.0 million in 2019, 2018 and 2017, respectively, paid to independent members of the Board of Directors and advisors as compensation for their services to the Company. The Company's consolidated statement of operations for the year ended December 31, 2019 also includes $3.2 million related to liability-based awards expected to be settled in cash.

Income Taxes

The Company accounts for income taxes using the asset and liability approach for financial accounting and reporting. The Company evaluates the probability of realizing the future benefits of its deferred tax assets and records a valuation allowance for the portion of any deferred tax assets when it is more likely than not that the benefit from the deferred tax asset will not be realized.

The Company recognizes the tax benefit of an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities based on the technical merits of the position. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. At December 31, 2019, 2018 and 2017, the Company had not established any reserves for, nor recorded any unrecognized tax benefits related to, uncertain tax positions.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

When necessary, the Company would include interest assessed by taxing authorities in "Interest expense" and penalties related to income taxes in "Other expense" on its consolidated statements of operations. The Company did not record any interest or penalties related to income taxes for the years ended December 31, 2019, 2018 and 2017.

On December 22, 2017, the President of the United States signed into law the Tax Cuts and Jobs Act. The legislation significantly changed U.S. tax law by, among other things, lowering corporate income tax rates, implementing a territorial tax system and imposing a repatriation tax on deemed repatriated earnings of foreign subsidiaries. The Tax Cuts and Jobs Act reduced the U.S. corporate income tax rate from a maximum of 35% to a flat rate of 21% effective January 1, 2018.

Allocation of Purchase Price in Business Combinations

As part of the Company's business strategy, it periodically pursues the acquisition of oil and natural gas properties. The purchase price in a business combination is allocated to the assets acquired and liabilities assumed based on their fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The most significant estimates in the allocation typically relate to the value assigned to proved oil and natural gas reserves and unproved and unevaluated properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Earnings Per Common Share

The Company reports basic earnings attributable to Matador Resources Company shareholders per common share, which excludes the effect of potentially dilutive securities, and diluted earnings attributable to Matador Resources Company shareholders per common share, which includes the effect of all potentially dilutive securities, unless their impact is anti-dilutive.

The following are reconciliations of the numerators and denominators used to compute the Company's basic and diluted earnings per common share as reported for the years ended December 31, 2019, 2018 and 2017 (in thousands, except per share data).

	Year Ended December 31,		
	2019	2018	2017
Net income attributable to Matador Resources Company shareholders — numerator	$ 87,777	$274,207	$125,867
Weighted average common shares outstanding — denominator			
Basic	116,555	113,580	102,029
Dilutive effect of options and restricted stock units	508	111	514
Diluted weighted average common shares outstanding	117,063	113,691	102,543
Earnings per common share attributable to Matador Resources Company shareholders			
Basic	$ 0.75	$ 2.41	$ 1.23
Diluted	$ 0.75	$ 2.41	$ 1.23

A total of 2.6 million, 1.6 million and 1.0 million options to purchase shares of Matador's common stock were excluded from the diluted weighted average common shares outstanding for the years ended December 31, 2019, 2018 and 2017, respectively, because their effects were anti-dilutive.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Credit Risk

The Company's cash is held in financial institutions and at times these amounts exceed the insurance limits of the Federal Deposit Insurance Corporation. Management believes, however, that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected.

The Company uses derivative financial instruments to mitigate its exposure to oil, natural gas and NGL price volatility. These transactions expose the Company to potential credit risk from its counterparties. The Company manages counterparty credit risk through established internal derivatives policies that are reviewed on an ongoing basis. Additionally, all of the Company's commodity derivative contracts at December 31, 2019 were with The Bank of Nova Scotia and BMO Harris Financing, Inc. (Bank of Montreal) (or affiliates thereof), parties that are lenders (or affiliates thereof) under the Company's revolving credit agreement.

Accounts receivable constitute the principal component of additional credit risk to which the Company may be exposed. The Company attempts to minimize credit risk exposure to counterparties by monitoring the financial condition and payment history of its purchasers and joint interest partners.

Recent Accounting Pronouncements

Income Taxes. In December 2019, the Financial Accounting Standards Board issued ASU 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes*, which removes certain exceptions to the general principles in Topic 740 and provides clarifications related to franchise taxes, transactions with a government that result in a step-up in the tax basis of goodwill, allocation of current and deferred income tax expense and the annual effective tax rate. This ASU is effective January 1, 2021, and its adoption is not expected to have a material impact on the Company's consolidated financial statements.

NOTE 3 — PROPERTY AND EQUIPMENT

The following table presents a summary of the Company's property and equipment balances as of December 31, 2019 and 2018 (in thousands).

	December 31,	
	2019	2018
Oil and natural gas properties		
Evaluated (subject to amortization)	$ 4,557,265	$ 3,780,236
Unproved and unevaluated (not subject to amortization)	1,126,992	1,199,511
Total oil and natural gas properties	5,684,257	4,979,747
Accumulated depletion	(2,603,681)	(2,273,010)
Net oil and natural gas properties	3,080,576	2,706,737
Midstream properties		
Midstream equipment and facilities	643,903	428,025
Accumulated depreciation	(38,473)	(24,351)
Net midstream properties	605,430	403,674
Other property and equipment		
Furniture, fixtures and other equipment	9,170	7,047
Software	8,099	8,039
Leasehold improvements	9,752	6,955
Total other property and equipment	27,021	22,041
Accumulated depreciation	(13,432)	(9,588)
Net other property and equipment	13,589	12,453
Net property and equipment	$ 3,699,595	$ 3,122,864

NOTE 3 — PROPERTY AND EQUIPMENT — Continued

The following table provides a breakdown of the Company's unproved and unevaluated property costs not subject to amortization as of December 31, 2019 and the year in which these costs were incurred (in thousands).

Description	2019	2018	2017	2016 and prior	Total
Costs incurred for					
Property acquisition	$ 43,795	$556,415	$204,425	$258,296	$1,062,931
Exploration wells	10,814	171	361	352	11,698
Development wells	52,144	149	70	—	52,363
Total	$106,753	$556,735	$204,856	$258,648	$1,126,992

Property acquisition costs primarily include leasehold costs paid to secure oil and natural gas mineral leases, but may also include broker and legal expenses, geological and geophysical expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Property acquisition costs are transferred into the amortization base on an ongoing basis as these properties are evaluated and proved reserves are established or impairment is determined. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions.

Property acquisition costs incurred that remain in unproved and unevaluated property at December 31, 2019 are related to the Company's leasehold and mineral acquisitions in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. These costs are associated with acreage for which proved reserves have yet to be assigned. A significant portion of these costs are associated with properties that are held by production or have automatic lease renewal options. As the Company drills wells and assigns proved reserves to these properties or determines that certain portions of this acreage, if any, cannot be assigned proved reserves, portions of these costs are transferred to the amortization base.

On September 12, 2018, the Company announced the successful acquisition of 8,400 gross and net leasehold acres in Lea and Eddy Counties, New Mexico for approximately $387 million in the Bureau of Land Management New Mexico Oil and Gas Lease Sale on September 5 and 6, 2018 (the "BLM Acquisition"). The BLM Acquisition was responsible for a significant portion of the Company's property acquisition costs in 2018.

Costs excluded from amortization also include those costs associated with exploration and development wells in progress or awaiting completion at year-end. These costs are transferred into the amortization base on an ongoing basis as these wells are completed and proved reserves are established or confirmed. These costs totaled $64.1 million at December 31, 2019. Of this total, $11.7 million was associated with exploration wells and $52.4 million was associated with development wells. The Company anticipates that most of the $64.1 million associated with these wells in progress at December 31, 2019 will be transferred to the amortization base during 2020. Unproved and unevaluated property costs for exploration and development wells incurred from 2016 through 2018 are costs related to the advanced preparation for wells that we intend to drill in the future.

NOTE 4 — LEASES

The Company determines if an arrangement is a lease at inception of the contract. If an arrangement is a lease, the present value of the related lease payments is recorded as a liability and an equal amount is capitalized as a right of use asset on the Company's consolidated balance sheet. The Company elected to include payments for non-lease components associated with certain leases when determining the present value of the lease payments. Right of use assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the lease. The Company's estimated incremental borrowing rate, determined at the lease commencement date using the Company's average secured borrowing rate, is used to calculate present value. The weighted average estimated incremental borrowing rate used for the year ended December 31, 2019 was 3.52% and 3.70% for operating leases and financing leases, respectively. For these purposes, the lease term includes options to extend the lease when it is reasonably certain that the Company will exercise such option. Leases with terms of 12 months or less at inception are not recorded on the consolidated balance sheet unless there is a significant cost to terminate the lease, including the cost of removal of the leased asset. As the Company is the responsible party under these arrangements, the Company records the resulting assets and liabilities on a gross basis in its consolidated balance sheets.

The following table presents supplemental consolidated statement of operations information related to lease expenses, on a gross basis, for the year ended December 31, 2019 (in thousands). Lease payments represent gross payments to vendors, which, for certain of our operating assets, are partially offset by amounts received from other working interest owners in our operated wells.

	Year Ended December 31, 2019
Operating leases	
Lease operating	$11,877
Plant and other midstream services	110
General and administrative	3,209
Total operating leases (1)	15,196
Short-term leases	
Lease operating	10,441
Plant and other midstream services	4,983
General and administrative	27
Total short-term leases (2) (3)	15,451
Financing leases	
Depreciation of assets	976
Interest on lease liabilities	134
Total financing leases	1,110
Total lease expense	$31,757

(1) Does not include gross payments related to drilling rig leases of $28.1 million for the year ended December 31, 2019 that were capitalized and recorded in "Oil and natural gas properties, full-cost method" in the consolidated balance sheet at December 31, 2019.

(2) These costs are related to leases that are not recorded as right of use assets or lease liabilities in the consolidated balance sheet as they are short-term leases.

(3) Does not include gross payments related to short-term drilling rig leases and other equipment rentals of $90.3 million for the year ended December 31, 2019 that were capitalized and recorded in "Oil and natural gas properties, full-cost method" in the consolidated balance sheet at December 31, 2019.

NOTE 4 — LEASES — Continued

The following table presents supplemental consolidated balance sheet information related to leases as of December 31, 2019 (in thousands).

	December 31, 2019
Operating leases	
Other long-term assets	$ 85,668
Other current liabilities	$(50,164)
Other long-term liabilities	(41,459)
Total operating lease liabilities	$(91,623)
Financing leases	
Other property and equipment, at cost	$ 2,677
Accumulated depreciation	(1,324)
Net property and equipment	$ 1,353
Other current liabilities	$ (799)
Other long-term liabilities	(524)
Total financing lease liabilities	$ (1,323)

The following table presents supplemental consolidated cash flow information related to lease payments for the year ended December 31, 2019 (in thousands).

	Year Ended December 31, 2019
Cash paid related to lease liabilities	
Operating cash payments for operating leases	$ 14,941
Investing cash payments for operating leases	$ 28,034
Financing cash payments for financing leases	$ 918
Right of use assets obtained in exchange for lease obligations entered into during the period	
Operating leases	$ 59,740
Financing leases	$ 597

The following table presents the maturities of lease liabilities at December 31, 2019 (in years).

Weighted-Average Remaining Lease Term	December 31, 2019
Operating leases	2.7
Financing leases	2.1

NOTE 4 — LEASES — Continued

The following table presents a schedule of future minimum lease payments required under all lease agreements as of December 31, 2019 and 2018, respectively (in thousands).

	December 31, 2019	
	Operating Leases	Financing Leases
2020	$ 50,164	$ 799
2021	27,279	517
2022	5,010	179
2023	4,177	—
2024	4,217	—
Thereafter	5,716	—
Total lease payments	96,563	1,495
Less imputed interest	(4,940)	(172)
Total lease obligations	91,623	1,323
Less current obligations	(50,164)	(799)
Long-term lease obligations	$ 41,459	$ 524

	December 31, 2018	
	Operating Leases	Financing Leases
2019	$ 39,457	$ 1,240
2020	12,009	913
2021	3,513	534
2022	3,209	455
2023	3,234	—
Thereafter	7,680	—
Total lease payments	69,102	3,142
Less imputed interest	(4,300)	(130)
Total lease obligations	64,802	3,012
Less current obligations	(39,457)	(1,240)
Long-term lease obligations	$ 25,345	$ 1,772

NOTE 5 — ASSET RETIREMENT OBLIGATIONS

In general, the Company's asset retirement obligations relate to future costs associated with plugging and abandonment of its oil, natural gas and salt water disposal wells, removal of pipelines, equipment and facilities from leased acreage and returning such land to its original condition. The amounts recognized are based on numerous estimates and assumptions, including future retirement costs, future recoverable quantities of oil and natural gas, future inflation rates and the Company's credit-adjusted risk-free interest rate. Revisions to the liability can occur due to changes in these estimates and assumptions or if federal or state regulators enact new plugging and abandonment requirements. At the time of the actual plugging and abandonment of its oil and natural gas wells, the Company includes any gain or loss associated with the operation in the amortization base to the extent the actual costs are different from the estimated liability.

NOTE 5 — ASSET RETIREMENT OBLIGATIONS — Continued

The following table summarizes the changes in the Company's asset retirement obligations for the years ended December 31, 2019 and 2018 (in thousands).

	Year Ended December 31,	
	2019	2018
Beginning asset retirement obligations	$31,086	$26,256
Liabilities incurred during period	3,811	3,566
Liabilities settled during period	(155)	(708)
Revisions in estimated cash flows	1,792	442
Divestitures during the period	(2,145)	—
Accretion expense	1,822	1,530
Ending asset retirement obligations	36,211	31,086
Less: current asset retirement obligations (1)	(619)	(1,350)
Long-term asset retirement obligations	$35,592	$29,736

(1) Included in "Accrued liabilities" in the Company's consolidated balance sheets at December 31, 2019 and 2018.

NOTE 6 — BUSINESS COMBINATIONS AND DIVESTITURES

Joint Ventures

On February 17, 2017, the Company contributed substantially all of its midstream assets located in the Rustler Breaks (Eddy County, New Mexico) and Wolf (Loving County, Texas) asset areas in the Delaware Basin to San Mateo I, a joint venture with a subsidiary of Five Point Energy LLC ("Five Point"). The midstream assets contributed to San Mateo I include (i) the Black River Processing Plant; (ii) one salt water disposal well and a related commercial salt water disposal facility in the Rustler Breaks asset area; (iii) three salt water disposal wells and related commercial salt water disposal facilities in the Wolf asset area; and (iv) substantially all related oil, natural gas and water gathering systems and pipelines in both the Rustler Breaks and Wolf asset areas (collectively, the "Delaware Midstream Assets"). The Company continues to operate the Delaware Midstream Assets and San Mateo I's other assets. The Company retained its ownership in certain midstream assets owned in South Texas and Northwest Louisiana, which are not part of San Mateo.

The Company and Five Point own 51% and 49% of San Mateo I, respectively. Five Point provided initial cash consideration of $176.4 million to San Mateo I in exchange for its 49% interest. Approximately $171.5 million of this cash contribution by Five Point was distributed by San Mateo I to the Company as a special distribution. The Company earned, and Five Point paid to the Company, $14.7 million in performance incentives during each of the twelve months ended December 31, 2019 and 2018. As of February 28, 2020, the Company had received an additional $14.7 million in performance incentives from Five Point and may earn an additional $29.4 million in performance incentives over the next two years. These performance incentives are recorded as additional contributions related to the formation of the San Mateo I as they are received. The Company contributed the Delaware Midstream Assets and $5.1 million in cash to San Mateo I in exchange for its 51% interest. San Mateo I is consolidated in the Company's financial statements with Five Point's interest in San Mateo I being accounted for as a non-controlling interest.

The Company dedicated its current and future leasehold interests in the Rustler Breaks and Wolf asset areas to San Mateo I pursuant to 15-year, fixed-fee natural gas, oil and salt water gathering agreements and salt water disposal agreements, effective as of February 1, 2017. In addition, the Company dedicated its current and future leasehold interests in the Rustler Breaks asset area to San Mateo I pursuant to a 15-year, fixed-fee natural gas processing agreement (see Note 14).

NOTE 6 — BUSINESS COMBINATIONS AND DIVESTITURES — Continued

On February 25, 2019, the Company announced the formation of San Mateo II, a strategic joint venture with a subsidiary of Five Point designed to expand the Company's midstream operations in the Delaware Basin, specifically in Eddy County, New Mexico. San Mateo II is owned 51% by the Company and 49% by Five Point. In addition, Five Point has committed to pay $125 million of the first $150 million of capital expenditures incurred by San Mateo II to develop facilities in the Stebbins area and surrounding leaseholds in the southern portion of the Arrowhead asset area (the "Greater Stebbins Area") and the Stateline asset area. Upon formation of San Mateo II, in the first quarter of 2019, the Company contributed $1.0 million of property to San Mateo II. During the year ended December 31, 2019, the Company contributed $15.5 million of cash, and Five Point contributed $69.0 million of cash, of which $28.4 million was paid to carry Matador's proportionate interest in San Mateo II and was therefore recorded in "Additional paid-in capital" in the consolidated balance sheet, net of the $5.9 million deferred tax impact to Matador related to this equity contribution. In addition, the Company has the ability to earn up to $150.0 million in deferred performance incentives over the next several years, plus additional performance incentives for securing volumes from third-party customers.

In connection with the formation of San Mateo II, the Company dedicated to San Mateo II acreage in the Greater Stebbins Area and the Stateline asset area pursuant to 15-year, fixed-fee oil, natural gas and salt water gathering, natural gas processing and salt water disposal agreements (see Note 14).

Divestitures

During 2019, we converted approximately $21.9 million of non-core assets to cash. These properties were primarily located in South Texas and Northwest Louisiana and East Texas but included a small portion of our leasehold in a non-operated area of the Delaware Basin.

NOTE 7 — DEBT

At December 31, 2019, the Company had $1.05 billion of outstanding senior notes due 2026, $255.0 million in borrowings outstanding under its revolving credit facility and approximately $46.1 million in outstanding letters of credit issued pursuant to its revolving credit facility. At December 31, 2019, San Mateo I had $288.0 million in borrowings outstanding under its revolving credit facility and approximately $16.2 million in outstanding letters of credit issued pursuant to its revolving credit facility.

Credit Agreements

MRC Energy Company

On September 28, 2012, the Company amended and restated its revolving credit facility with the lenders party thereto, led by Royal Bank of Canada ("RBC") as administrative agent (the "Credit Agreement"). MRC Energy Company, a subsidiary of Matador that directly or indirectly holds the ownership interests in the Company's other operating subsidiaries, other than its less-than-wholly-owned subsidiaries, is the borrower under the Credit Agreement. Borrowings are secured by mortgages on at least 80% of the Company's proved oil and natural gas properties and by the equity interests of certain of MRC Energy Company's wholly-owned subsidiaries, which are also guarantors. San Mateo and its subsidiaries are not guarantors of the Credit Agreement. In addition, all obligations under the Credit Agreement are guaranteed by Matador, the parent corporation. Various commodity hedging agreements with certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by certain eligible subsidiaries of MRC Energy Company. The Credit Agreement matures October 31, 2023.

NOTE 7 — DEBT — Continued

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of the Company's proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. The Company and the lenders may each request an unscheduled redetermination of the borrowing base once between scheduled redetermination dates.

In October 2018, the lenders under the Credit Agreement completed their review of the Company's proved oil and natural gas reserves at June 30, 2018. In connection with such review, the Company amended the Credit Agreement to, among other items, increase the maximum facility amount to $1.5 billion, increase the borrowing base to $850.0 million, increase the elected borrowing commitment to $500.0 million, extend the maturity to October 31, 2023, reduce borrowing rates by 0.25% per annum and set the maximum leverage ratio at 4.00 to 1.00.

In April 2019, the lenders completed their review of the Company's proved oil and natural gas reserves at December 31, 2018, and as a result, the borrowing base was increased from $850.0 million to $900.0 million. In October 2019, the lenders completed their review of the Company's proved oil and natural gas reserves at June 30, 2019, and as a result, the borrowing base was affirmed at $900.0 million. The Company elected to keep the borrowing commitment at $500.0 million, and the maximum facility amount remained $1.5 billion.

In February 2020, the lenders completed their review of the Company's proved oil and natural gas reserves at December 31, 2019, and as a result, the borrowing base was again affirmed at $900.0 million. The Company elected to increase the borrowing commitment from $500.0 million to $700.0 million, and the maximum facility amount remained $1.5 billion. This February 2020 redetermination constituted the regularly scheduled May 1 redetermination. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, the maximum facility amount and the elected borrowing commitment.

In the event of an increase in the elected commitment, the Company is required to pay a fee to the lenders equal to a percentage of the amount of the increase, which is determined based on market conditions at the time of the increase. If, upon a redetermination of the borrowing base, the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at such time, the Company would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

Total deferred loan costs were $1.6 million at December 31, 2019, and these costs are being amortized over the term of the Credit Agreement. The Company's effective interest rate under the Credit Agreement was 3.28% at December 31, 2019. At December 31, 2019 and February 25, 2020, the Company had $255.0 million and $255.0 million in borrowings outstanding under the Credit Agreement and approximately $46.1 million and $46.0 million in outstanding letters of credit issued pursuant to the Credit Agreement, respectively.

Borrowings under the Credit Agreement may be in the form of a base rate loan or a Eurodollar loan. If the Company borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the greatest of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate (as defined in the Credit Agreement) on such day, plus 0.50% and (iii) the daily adjusting LIBOR rate (as defined in the Credit Agreement) plus 1.0% plus, in each case, an amount ranging from 0.25% to 1.25% per annum depending on the level of borrowings under the Credit Agreement. If the Company borrows funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (x) the reserve adjusted LIBOR Rate (as defined in the Credit Agreement) plus (y) an amount ranging from 1.25%

NOTE 7 — DEBT — Continued

to 2.25% per annum depending on the level of borrowings under the Credit Agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by the Company. If the Company has outstanding borrowings under the Credit Agreement and interest rates increase, so will the Company's interest costs, which may have a material adverse effect on the Company's results of operations and financial condition.

A commitment fee of 0.375% to 0.50% per annum, depending on the level of borrowings under the Credit Agreement, is also paid quarterly in arrears. The Company includes this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees, if any, as interest expense and in its interest rate calculations and related disclosures. The Credit Agreement requires the Company to maintain a debt to EBITDA ratio, which is defined as debt outstanding (net of up to $50 million of cash or cash equivalents) divided by a rolling four quarter EBITDA calculation, of 4.00 or less.

Subject to certain exceptions, the Credit Agreement contains various covenants that limit the Company's and its restricted subsidiaries' ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of the Company's assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates;
- engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets; and
- take certain actions with respect to the Company's senior unsecured notes.

If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the outstanding borrowings or any reimbursement obligation under any letter of credit when due or any fees or other amounts within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving the Company or its subsidiaries; and
- a change of control, as defined in the Credit Agreement.

The Company believes that it was in compliance with the terms of the Credit Agreement at December 31, 2019.

NOTE 7 — DEBT — Continued

San Mateo Midstream, LLC

On December 19, 2018, San Mateo I entered into a $250.0 million credit facility led by The Bank of Nova Scotia, as administrative agent (the "San Mateo Credit Facility"), and including all lenders party to the Credit Agreement at that time. The San Mateo Credit Facility, which matures December 19, 2023, includes an accordion feature, which provides for potential increases to up to $400.0 million. The San Mateo Credit Facility is non-recourse with respect to Matador and its wholly-owned subsidiaries, as well as San Mateo II and its subsidiaries, but is guaranteed by San Mateo I's subsidiaries and secured by substantially all of San Mateo I's assets, including real property. In June and October 2019, pursuant to the accordion feature, the lender commitments under the San Mateo Credit Facility were increased to $325.0 million and $375.0 million, respectively.

Total deferred loan costs were $2.7 million at December 31, 2019, and these costs are being amortized over the term of the San Mateo Credit Facility. San Mateo I's effective interest rate under the San Mateo Credit Facility was 3.55% at December 31, 2019. At both December 31, 2019 and February 25, 2020, San Mateo I had $288.0 million in borrowings outstanding under the San Mateo Credit Facility and $16.2 million in outstanding letters of credit issued pursuant to the San Mateo Credit Facility.

Borrowings under the San Mateo Credit Facility may be in the form of a base rate loan or a Eurodollar loan. If San Mateo I borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the greatest of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate (as defined in the San Mateo Credit Facility) on such day, plus 0.50% and (iii) the Adjusted LIBO Rate (as defined in the San Mateo Credit Facility) plus 1.0% plus, in each case, an amount ranging from 0.50% to 1.50% per annum depending on San Mateo I's Consolidated Total Leverage Ratio (as defined in the San Mateo Credit Facility). If San Mateo I borrows funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (x) the Adjusted LIBO Rate for the chosen interest period plus (y) an amount ranging from 1.50% to 2.50% per annum depending on San Mateo I's Consolidated Total Leverage Ratio. If San Mateo I has outstanding borrowings under the San Mateo Credit Facility and interest rates increase, so will San Mateo I's interest costs, which may have a material adverse effect on San Mateo I's results of operations and financial condition.

A commitment fee of 0.30% to 0.50% per annum, depending on the unused availability under the San Mateo Credit Facility, is also paid quarterly in arrears. The Company includes this commitment fee, any amortization of deferred financing costs (including origination and amendment fees) and annual agency fees, if any, as interest expense and in its interest rate calculations and related disclosures. The San Mateo Credit Facility requires San Mateo I to maintain a debt to EBITDA ratio, which is defined as total consolidated funded indebtedness outstanding (as defined in the San Mateo Credit Facility) divided by a rolling four quarter EBITDA calculation, of 5.00 or less, subject to certain exceptions. The San Mateo Credit Facility also requires San Mateo I to maintain an interest coverage ratio, which is defined as a rolling four quarter EBITDA calculation divided by San Mateo I's consolidated interest expense, of 2.50 or more.

NOTE 7 — DEBT — Continued

Subject to certain exceptions, the San Mateo Credit Facility contains various covenants that limit San Mateo I's and its restricted subsidiaries' ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of San Mateo I's assets;
- enter into hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates;
- engage in certain asset dispositions, including a sale of all or substantially all of San Mateo I's assets; and
- issue equity interests in San Mateo I or its subsidiaries.

If an event of default exists under the San Mateo Credit Facility, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the outstanding borrowings or any reimbursement obligation under any letter of credit when due or any fees or other amounts within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the San Mateo Credit Facility or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving San Mateo I or its subsidiaries; and
- a change of control, as defined in the San Mateo Credit Facility.

The Company believes that San Mateo I was in compliance with the terms of the San Mateo Credit Facility at December 31, 2019.

Senior Unsecured Notes

On April 14, 2015, Matador issued $400.0 million of 6.875% senior notes due 2023 (the "Original 2023 Notes") in a private placement at par value. The Original 2023 Notes were later exchanged for a like principal amount of 6.875% senior notes due 2023 (the "2023 Exchange Notes") that were registered under the Securities Act of 1933, as amended (the "Securities Act"), at par value. On December 9, 2016, Matador issued $175.0 million of 6.875% senior notes due 2023 (the "Additional 2023 Notes") in a private placement, at 105.5% of par, plus accrued interest from October 15, 2016, resulting in an effective interest rate of 5.5%. The Company received net proceeds of approximately $181.5 million, including the issue premium, but after deducting the initial purchasers' discounts and estimated offering expenses and excluding accrued interest paid by buyers of the Additional 2023 Notes. The Additional 2023 Notes were later exchanged for a like principal amount of 6.875% senior notes due 2023 that were registered under the Securities Act (together with the 2023 Exchange Notes, the "2023 Notes").

On August 21, 2018, the Company issued $750.0 million of 5.875% senior notes due 2026 (the "Original 2026 Notes") in a private placement at par value (the "2026 Notes Offering"). The Company received net proceeds of approximately $740.0 million, after deducting the initial purchasers' discounts and offering expenses. In conjunction

NOTE 7 — DEBT — Continued

with the 2026 Notes Offering, in August and September 2018, respectively, the Company completed a tender offer to purchase for cash and subsequent redemption of all of the 2023 Notes (the "2023 Notes Tender Offer and Redemption"). The Company used a portion of the net proceeds from the 2026 Notes Offering to fund the 2023 Notes Tender Offer and Redemption. In connection with the 2023 Notes Tender Offer and Redemption, the Company incurred a loss of $31.2 million, including total payments of $30.4 million to holders of the 2023 Notes as a result of the tender premium and the required 105.156% redemption price payable pursuant to the 2023 Notes indenture.

On October 4, 2018, the Company issued an additional $300.0 million of 5.875% senior notes due 2026 (the "Additional 2026 Notes"). The Additional 2026 Notes were issued pursuant to, and are governed by, the same indenture governing the Original 2026 Notes (the "Indenture"). The Additional 2026 Notes were issued at 100.5% of par, plus accrued interest from August 21, 2018. The Company received net proceeds from this offering of approximately $297.3 million, including the issue premium, but after deducting the initial purchasers' discounts and estimated offering expenses and excluding accrued interest from August 21, 2018 paid by the initial purchasers of the Additional 2026 Notes. The proceeds from this offering were used to repay a portion of the outstanding borrowings under the Credit Agreement, which were incurred in connection with the BLM Acquisition.

In December 2018, the Company exchanged substantially all of the Original 2026 Notes and Additional 2026 Notes for a like principal amount of 5.875% senior notes due 2026 that were registered under the Securities Act (the "Notes"). The terms of the Notes are substantially the same as the terms of the Original 2026 Notes and Additional 2026 Notes except that the transfer restrictions, registration rights and provisions for additional interest relating to the Original 2026 Notes and Additional 2026 Notes do not apply to the Notes. The Notes will mature September 15, 2026, and interest is payable on the Notes semi-annually in arrears on each March 15 and September 15. The Notes are guaranteed on a senior unsecured basis by certain subsidiaries of the Company (the "Guarantors"). San Mateo and its subsidiaries are not Restricted Subsidiaries under the Indenture or Guarantors of the Notes (see Note 17).

On or after September 15, 2021, the Company may redeem all or a part of the Notes at any time or from time to time at the following redemption prices (expressed as percentages of principal amount) plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the twelve-month period beginning on September 15 of the years indicated below:

Year	Redemption Price
2021	104.406%
2022	102.938%
2023	101.469%
2024 and thereafter	100.000%

At any time prior to September 15, 2021, the Company may redeem up to 35% of the aggregate principal amount of the Notes with net proceeds from certain equity offerings at a redemption price of 105.875% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, provided that (i) at least 65% in aggregate principal amount of the Notes (including any additional notes) originally issued remains outstanding immediately after the occurrence of such redemption (excluding Notes held by the Company and its subsidiaries) and (ii) each such redemption occurs within 180 days of the date of the closing of the related equity offering.

NOTE 7 — DEBT — Continued

In addition, at any time prior to September 15, 2021, the Company may redeem all or part of the Notes at a redemption price equal to the sum of:

(i) the principal amount thereof, plus

(ii) the excess, if any, of (a) the present value at such time of (1) the redemption price of such Notes at September 15, 2021 plus (2) any required interest payments due on such Notes through September 15, 2021, discounted to the redemption date on a semi-annual basis using a discount rate equal to the Treasury Rate (as defined in the Indenture) plus 50 basis points, over (b) the principal amount of such Notes, plus

(iii) accrued and unpaid interest, if any, to the redemption date.

Subject to certain exceptions, the Indenture contains various covenants that limit the Company's ability to take certain actions, including, but not limited to, the following:

- incur additional indebtedness;
- sell assets;
- pay dividends or make certain investments;
- create liens that secure indebtedness;
- enter into transactions with affiliates; and
- merge or consolidate with another company.

In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to Matador, any Restricted Subsidiary (as defined in the Indenture) that is a Significant Subsidiary (as defined in the Indenture) or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary, all outstanding Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding Notes may declare all the Notes to be due and payable immediately. Events of default include, but are not limited to, the following events:

- default for 30 days in the payment when due of interest on the Notes;
- default in the payment when due of the principal of, or premium, if any, on the Notes;
- failure by the Company to comply with its obligations to offer to purchase or purchase Notes pursuant to the change of control or asset sale covenants of the Indenture or to comply with the covenant relating to mergers;
- failure by the Company for 180 days after notice to comply with its reporting obligations under the Indenture;
- failure by the Company for 60 days after notice to comply with any of the other agreements in the Indenture;
- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries in the aggregate principal amount of $50.0 million or more;
- failure by the Company or any Restricted Subsidiary to pay certain final judgments aggregating in excess of $50.0 million within 60 days;
- any subsidiary guarantee by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker; and
- certain events of bankruptcy or insolvency with respect to the Company or any Restricted Subsidiary that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary.

NOTE 7 — DEBT — Continued

The outstanding borrowings of $255.0 million at December 31, 2019 under the Credit Agreement mature on October 31, 2023. The outstanding borrowings of $288.0 million at December 31, 2019 under the San Mateo Credit Facility mature on December 19, 2023. The $1.05 billion of outstanding Notes at December 31, 2019 mature on September 15, 2026.

NOTE 8 — INCOME TAXES

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and the tax bases of assets and liabilities. The Company's net deferred tax position as of December 31, 2019 and 2018 is as follows (in thousands).

	December 31,	
	2019	2018
Deferred tax assets		
Net operating loss carryforwards	$ 119,900	$ 116,374
Percentage depletion carryover	1,467	1,624
Compensation	13,690	10,574
Lease liabilities	17,107	—
Other	9,099	7,207
Total deferred tax assets	161,263	135,779
Valuation allowance on deferred tax assets	(6,736)	(6,519)
Total deferred tax assets, net of valuation allowance	154,527	129,260
Deferred tax liabilities		
Unrealized gain on derivatives	—	(12,326)
Property and equipment	(151,504)	(100,634)
Less than wholly-owned subsidiaries	(20,604)	(6,808)
Lease right of use assets	(17,107)	—
Other	(2,641)	(2,256)
Total deferred tax liabilities	(191,856)	(122,024)
Net deferred tax (liabilities) assets	$ (37,329)	$ 7,236

At December 31, 2019, the Company had net operating loss carryforwards of $525.2 million for federal income tax purposes and $163.9 million for state income tax purposes available to offset future taxable income, as limited by the applicable provisions, and which expire at various dates beginning in 2027 for the federal net operating loss carryforwards. The state net operating loss carryforwards begin expiring at various dates beginning in 2024; however, the significant portion of the Company's state net operating loss carryforwards expire beginning in 2027.

At December 31, 2017, the Company's deferred tax assets exceeded its deferred tax liabilities due to the deferred tax assets generated by impairment charges recorded in 2016 and 2015. As a result, the Company established a valuation allowance against most of the deferred tax assets beginning in the third quarter of 2015. Due to a variety of factors, including the Company's significant net income in 2017 and 2018, the Company's federal valuation allowance and a portion of the Company's state valuation allowance were reversed at December 31, 2018 as the deferred tax assets were determined to be more likely than not to be utilized. As a portion of the Company's state net operating loss carryforwards are not expected to be utilized before expiration, a valuation allowance will continue to be recognized until the state deferred tax assets are more likely than not to be utilized.

NOTE 8 — INCOME TAXES — Continued

The current income tax provision and the deferred income tax provision for the years ended December 31, 2019, 2018 and 2017 were comprised of the following (in thousands).

	Year Ended December 31,		
	2019	2018	2017
Current income tax (benefit) provision			
Federal income tax	$ —	$ (455)	$(8,178)
State income tax	—	—	21
Net current income tax benefit	$ —	$ (455)	$(8,157)
Deferred income tax provision (benefit)			
Federal income tax	$29,171	$(20,457)	$ —
State income tax	6,361	13,221	—
Net deferred income tax provision (benefit)	$35,532	$ (7,236)	$ —

Reconciliations of the tax expense (benefit) computed at the statutory federal rate to the Company's total income tax provision (benefit) for the years ended December 31, 2019, 2018 and 2017 is as follows (in thousands).

	Year Ended December 31,		
	2019	2018	2017
Federal tax expense at statutory rate (1)	$33,441	$ 61,543	$ 45,447
State income tax	6,141	16,181	368
Permanent differences	(4,267)	(2,488)	(4,740)
AMT credit refundable	—	455	8,178
Tax Cuts and Jobs Act rate change	—	—	51,525
Change in federal valuation allowance	—	(80,003)	(101,917)
Change in state valuation allowance	217	(2,924)	1,139
Net deferred income tax provision (benefit)	35,532	(7,236)	—
Net current income tax benefit	—	(455)	(8,157)
Total income tax provision (benefit)	$35,532	$ (7,691)	$ (8,157)

(1) The statutory federal tax rate was 21% for the years ended December 31, 2019 and 2018 and 35% for the year ended December 31, 2017.

The Company files a United States federal income tax return and several state tax returns, a number of which remain open for examination. The earliest tax year open for examination for the federal, the State of New Mexico and the State of Louisiana tax returns is 2016. The earliest tax year open for examination for the State of Texas tax return is 2015.

The Company has evaluated all tax positions for which the statute of limitations remains open and believes that the material positions taken would more likely than not be sustained by examination. Therefore, at December 31, 2019, the Company had not established any reserves for, nor recorded any unrecognized benefits related to, uncertain tax positions.

NOTE 8 — INCOME TAXES — Continued

Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to reverse. As a result of the reduction in the U.S. corporate income tax rate from 35% to 21% under the Tax Cuts and Jobs Act, the Company revalued its deferred tax assets and liabilities at December 31, 2017, which resulted in a $51.5 million tax provision. As the Company maintained a valuation allowance against its federal and state deferred tax assets at December 31, 2017, a corresponding reduction in the valuation allowance was recorded against this tax provision; therefore, there was no net impact to the Company's consolidated statement of operations for the year ended December 31, 2017 as a result of this corporate income tax rate change.

Corporate alternative minimum taxes were also repealed under the Tax Cuts and Jobs Act; therefore, corporate alternative minimum tax carryforwards are expected to be refunded. As a result, the Company recorded $0.5 million and $8.2 million, respectively, as a current income tax benefit in its consolidated statements of operations for the years ended December 31, 2018 and 2017.

NOTE 9 — STOCK-BASED COMPENSATION

Stock Options, Restricted Stock, Restricted Stock Units, Stock and Performance Awards

In 2003, the Company's Board of Directors and shareholders approved the 2003 Plan. The 2003 Plan, as amended, provided that a maximum of 3,481,569 shares of common stock in the aggregate could be issued pursuant to options or restricted stock grants. The persons eligible to receive awards under the 2003 Plan included employees, directors, contractors or advisors of the Company.

In 2012, the Board of Directors adopted and shareholders approved the 2012 Incentive Plan. The 2012 Incentive Plan provided for a maximum of 8,700,000 shares of common stock in the aggregate that could be issued pursuant to options, restricted stock, stock appreciation rights, restricted stock units or other performance award grants. The persons eligible to receive awards under the 2012 Incentive Plan included employees, directors, contractors or advisors of the Company.

In 2019, the Board of Directors adopted and shareholders approved the 2019 Incentive Plan. As of December 31, 2019, the 2019 Incentive Plan provided for a maximum of 3,433,671 shares of common stock in the aggregate that may be issued pursuant to grants of options, restricted stock, stock appreciation rights, restricted stock units or other performance award grants. The persons eligible to receive awards under the 2019 Incentive Plan include employees, directors, contractors or advisors of the Company. The primary purpose of the 2019 Incentive Plan is to attract and retain key employees, directors, contractors or advisors of the Company. With the adoption of the 2019 Incentive Plan, the Company does not expect to make any future awards under the 2003 Plan or the 2012 Incentive Plan, but both plans will remain in place until all awards outstanding under such plans have been settled. As of February 25, 2020, no awards remained outstanding under the 2003 Plan.

The 2003 Plan, the 2012 Incentive Plan and the 2019 Incentive Plan are administered by the independent members of the Board of Directors, which, upon recommendation of the Strategic Planning and Compensation Committee of the Board of Directors, determine the number of options, restricted shares or other awards to be granted, the effective dates, the terms of the grants and the vesting periods. The Company typically uses newly issued shares of common stock to satisfy option exercises or restricted share grants. At December 31, 2018, all stock-based compensation awards granted since 2012 had been granted under the 2012 Incentive Plan and substantially all are equity-based awards for which the fair value is fixed at the grant date, while all stock-based compensation awards granted prior to January 1, 2012 were granted under the 2003 Plan and were liability-based awards for which the fair value was remeasured at each reporting period.

NOTE 9 — STOCK-BASED COMPENSATION — Continued

During the year ended December 31, 2019, the Company began granting both equity-based and liability-based awards under the 2019 Incentive Plan. The fair value of equity-based awards is fixed at the grant date, while the fair value of liability-based awards is remeasured at each reporting period.

Stock Options

Under the 2003 Plan, the 2012 Incentive Plan and the 2019 Incentive Plan, stock option awards have been granted to purchase the Company's common stock at an exercise price equal to the fair market value on the date of grant, a typical vesting period of three or four years and a typical maximum term of five, six or 10 years. The 2003 Plan and the 2012 Incentive Plan define fair market value as the closing price of Matador's common stock on the date of grant. Under the 2019 Incentive Plan, such fair market value of a stock option is determined using the closing price of Matador's common stock on the trading day prior to the date of grant. All option awards granted under the 2003 Plan and still outstanding as of December 31, 2019 were settled in the first quarter of 2020.

The fair value of the 65,000, 67,500 and 75,000 stock option awards outstanding under the 2003 Plan at December 31, 2019, 2018 and 2017, respectively, was estimated using the following weighted average assumptions.

	2019	2018	2017
Stock option pricing model	Black Scholes Merton	Black Scholes Merton	Black Scholes Merton
Expected option life	0.14 years	1.14 years	2.14 years
Risk-free interest rate	1.54%	2.48%	1.98%
Volatility	32.38%	37.94%	43.60%
Dividend yield	—%	—%	—%
Estimated forfeiture rate	—%	—%	—%

The weighted average grant date fair value for stock option awards granted under the 2012 Incentive Plan and the 2019 Incentive Plan were estimated using the following weighted average assumptions during the years ended December 31, 2019, 2018 and 2017.

	2019	2018	2017
Stock option pricing model	Black Scholes Merton	Black Scholes Merton	Black Scholes Merton
Expected option life	4.00 years	4.00 years	4.00 years
Risk-free interest rate	1.46%	2.51%	1.77%
Volatility	48.52%	45.17%	47.00%
Dividend yield	—%	—%	—%
Estimated forfeiture rate	4.43%	2.24%	3.66%
Weighted average fair value of stock option awards granted during the year	$5.04	$12.64	$10.49

The Company estimated the future volatility of its common stock using the historical value of its stock for a period of time commensurate with the expected term of the stock option. The expected term was estimated using the simplified method outlined in Staff Accounting Bulletin Topic 14. The risk-free interest rate is the rate for constant yield U.S. Treasury securities with a term to maturity that is consistent with the expected term of the award.

NOTE 9 — STOCK-BASED COMPENSATION — Continued

Summarized information about stock options outstanding at December 31, 2019 under the 2003 Plan, the 2012 Incentive Plan and the 2019 Incentive Plan (collectively, the "LTIPs") is as follows.

	Number of options (in thousands)	Weighted average exercise price
Options outstanding at December 31, 2018	3,225	$23.48
Options granted	540	$14.80
Options exercised	(223)	$14.93
Options forfeited	(10)	$27.91
Options expired	(272)	$23.22
Options outstanding at December 31, 2019	3,260	$22.64

	Options outstanding at December 31, 2019			Options exercisable at December 31, 2019	
Range of exercise prices	Shares outstanding (in thousands)	Weighted average remaining contractual life	Weighted average exercise price	Shares exercisable (in thousands)	Weighted average exercise price
$9.00	65	0.14	$ 9.00	65	$ 9.00
$13.22 - $15.40	933	3.74	$14.87	395	$14.97
$20.01 - $22.70	663	0.20	$21.94	658	$21.95
$25.31 - $29.68	1,599	3.37	$28.01	897	$27.66

At December 31, 2019, the aggregate intrinsic value was $3.3 million for outstanding options and $1.8 million for exercisable options, based on the closing price of Matador's common stock on the appropriate date under the LTIPs. The remaining weighted average contractual term of exercisable options at December 31, 2019 was 1.69 years.

The total intrinsic value of options exercised during the years ended December 31, 2019, 2018 and 2017 was $0.8 million, $7.0 million and $13.2 million, respectively. The tax related benefit realized from the exercise of stock options totaled $2.8 million, $5.7 million and $5.0 million for the years ended December 31, 2019, 2018 and 2017, respectively.

At December 31, 2019, the total remaining unrecognized compensation expense related to unvested stock options was approximately $5.5 million and the weighted average remaining requisite service period (vesting period) of all unvested stock options was 1.72 years.

The fair value of options vested during 2019, 2018 and 2017 was $9.7 million, $11.8 million and $2.1 million, respectively.

NOTE 9 — STOCK-BASED COMPENSATION — Continued

Service-Based Restricted Stock, Restricted Stock Units and Common Stock

The Company has granted stock, restricted stock and restricted stock unit awards to employees, outside directors and advisors of the Company under the LTIPs. The stock and restricted stock are issued upon grant, with the restrictions, if any, being removed upon vesting. The equity-based restricted stock units are issued upon vesting, unless the recipient makes an election to defer issuance for a set term after vesting. Liability-based restricted stock units are settled in cash upon vesting. Restricted stock and restricted stock units granted in 2018 and 2017 were service-based awards and vest over the service period, which is one to four years. Restricted stock and restricted stock units granted in 2019 were either service-based awards, which will settle in cash or equity, or performance-based restricted stock units, which vest in an amount between zero and 200% of the target units granted based on the Company's relative total shareholder return over the three-year period ending December 31, 2021, as compared to a designated peer group, and will be settled in stock. All restricted stock and restricted stock unit awards outstanding at December 31, 2019 were granted under the 2012 Incentive Plan and the 2019 Incentive Plan.

Equity-Based

A summary of the non-vested equity-based restricted stock and restricted stock units as of December 31, 2019 is presented below (in thousands, except fair value).

	Restricted Stock		Restricted Stock Units			
	Service Based		Service Based		Performance Based	
Non-vested restricted stock and restricted stock units	Shares	Weighted average fair value	Shares	Weighted average fair value	Shares	Weighted average fair value
Non-vested at December 31, 2018	1,356	$25.87	58	$27.48	—	$ —
Granted	240	$19.36	100	$16.06	428	$20.00
Vested	(674)	$23.02	(57)	$27.47	—	$ —
Forfeited	(25)	$28.39	(9)	$17.31	—	$ —
Non-vested at December 31, 2019	897	$26.19	92	$16.06	428	$20.00

Liability-Based

A summary of the non-vested liability-based restricted stock units as of December 31, 2019 is presented below (in thousands, except fair value).

Non-vested restricted stock units	Shares
Non-vested at December 31, 2018	—
Granted	687
Vested	—
Forfeited	(1)
Non-vested at December 31, 2019	686

At December 31, 2019, the aggregate intrinsic value for the restricted stock and restricted stock units outstanding was $37.7 million, of which $12.3 million is expected to be settled in cash as calculated based on the maximum number of shares of restricted stock and restricted stock units vesting, based on the closing price of Matador's common stock on the appropriate date under the LTIPs.

NOTE 9 — STOCK-BASED COMPENSATION — Continued

At December 31, 2019, the total remaining unrecognized compensation expense related to unvested restricted stock and restricted stock units was approximately $28.3 million, of which $9.1 million is expected to be settled in cash, and the weighted average remaining requisite service period (vesting period) of all non-vested restricted stock and restricted stock units was 1.80 years.

The fair value of restricted stock and restricted stock units vested during 2019, 2018 and 2017 was $13.6 million, $13.0 million and $9.9 million, respectively.

Summary

During the years ended December 31, 2019, 2018 and 2017, the total expense attributable to stock options was $6.4 million, $6.3 million and $7.1 million, respectively. At December 31, 2019, 2018 and 2017, the Company recorded a decrease of $0.1 million to current liabilities, a decrease of $1.1 million to long-term liabilities and an increase of $0.4 million to long-term liabilities, respectively, related to its outstanding liability-based stock options. The Company did not settle any liability-based awards in cash for the years ended December 31, 2019, 2018 and 2017, respectively. During the years ended December 31, 2019, 2018 and 2017, the total expense attributable to restricted stock and restricted stock units was $20.2 million, $15.3 million and $12.9 million, respectively. During the years ended December 31, 2019, 2018 and 2017, the Company capitalized $5.0 million, $4.4 million and $4.1 million, respectively, related to stock-based compensation and expensed the remaining $21.6 million, $17.2 million and $16.7 million, respectively.

The total tax benefit recognized for all stock-based compensation was $5.6 million, $4.8 million and $6.8 million for the years ended December 31, 2019, 2018 and 2017, respectively.

NOTE 10 — EMPLOYEE BENEFIT PLANS

401(k) Plan

All full-time Company employees are eligible to join the Company's defined contribution retirement plan the first day of the calendar month immediately following their date of employment. Each employee may contribute up to the maximum allowable under the Internal Revenue Code. Each year, the Company makes a contribution to the plan which equals 3% of the employee's annual compensation, referred to as the Employer's Safe Harbor Non-Elective Contribution, which totaled $1.4 million, $1.1 million and $0.9 million in 2019, 2018 and 2017, respectively. In addition, each year, the Company may make a discretionary matching contribution, as well as additional contributions. The Company's discretionary matching contributions totaled $1.7 million, $1.4 million and $1.1 million in 2019, 2018 and 2017, respectively. The Company made no additional contributions in any reporting period presented.

NOTE 11 — EQUITY

Common Stock

On May 17, 2018, the Company completed a public offering of 7,000,000 shares of its common stock. After deducting offering costs totaling approximately $0.2 million, the Company received net proceeds of approximately $226.4 million.

On October 10, 2017, the Company completed a public offering of 8,000,000 shares of its common stock. After deducting offering costs totaling approximately $0.3 million, the Company received net proceeds of approximately $208.4 million.

On June 1, 2017, the shareholders of the Company approved an amendment to the Company's Amended and Restated Certificate of Formation that authorized an increase in the number of authorized shares of common stock from 120,000,000 to 160,000,000 shares.

Treasury Stock

On October 24, 2019, October 25, 2018 and November 1, 2017, Matador's Board of Directors canceled all of the shares of treasury stock outstanding as of September 30, 2019, 2018 and 2017, respectively. These shares were restored to the status of authorized but unissued shares of common stock of the Company.

The shares of treasury stock outstanding at December 31, 2019, 2018 and 2017 represent forfeitures of non-vested restricted stock awards and forfeitures of fully vested restricted stock awards due to net share settlements with employees.

Preferred Stock

The Company's Amended and Restated Certificate of Formation authorizes 2,000,000 shares of preferred stock. Before any such shares are issued, the Board of Directors shall fix and determine the designations, preferences, limitations and relative rights, including voting rights of the shares of each such series.

NOTE 12 — DERIVATIVE FINANCIAL INSTRUMENTS

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil, natural gas and NGL prices. The Company records derivative financial instruments on its consolidated balance sheets as either assets or liabilities measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments. As a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statements of operations as an unrealized gain or loss. The fair value of the Company's derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company has evaluated and considered the credit standings of its counterparties in determining the fair value of its derivative financial instruments.

At December 31, 2019, the Company had various costless collar and swap contracts open and in place to mitigate its exposure to oil price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and price floor and ceiling and fixed price for the swaps. Each contract is set to expire at varying times during 2020, 2021 and 2022. The Company had no open contracts associated with natural gas or NGL prices at December 31, 2019.

NOTE 12 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following is a summary of the Company's open costless collar contracts for oil at December 31, 2019.

Commodity	Calculation Period	Notional Quantity (Bbl or MMBtu)	Weighted Average Price Floor ($/Bbl or $/MMBtu)	Weighted Average Price Ceiling ($/Bbl or $/MMBtu)	Fair Value of Asset (Liability) (thousands)
Oil	01/01/2020 - 12/31/2020	7,200,000	$47.69	$66.62	$630
Total open costless collar contracts					$630

The following is a summary of the Company's open basis swaps contracts for oil at December 31, 2019.

Commodity	Calculation Period	Notional Quantity (Bbl or Gal)	Fixed Price ($/Bbl or $/Gal)	Fair Value of Asset (Liability) (thousands)
Oil Basis Swaps	01/01/2020 - 12/31/2020	9,774,000	$0.61	$(2,528)
Oil Basis Swaps	01/01/2021 - 12/31/2021	6,480,000	$0.82	$(1,523)
Oil Basis Swaps	01/01/2022 - 12/31/2022	3,600,000	$0.90	$ (460)
Total open swap contracts				$(4,511)

At December 31, 2019, the Company had an aggregate net liability value for open derivative financial instruments of $3.9 million.

The Company's derivative financial instruments are subject to master netting arrangements, and the Company's counterparties allow for cross-commodity master netting provided the settlement dates for the commodities are the same. The Company does not present different types of commodities with the same counterparty on a net basis in its consolidated balance sheets.

The following table presents the gross asset and liability fair values of the Company's commodity price derivative financial instruments and the location of these balances in the consolidated balance sheets as of December 31, 2019 and December 31, 2018 (in thousands).

Derivative Instruments	Gross amounts recognized	Gross amounts netted in the consolidated balance sheets	Net amounts presented in the consolidated balance sheets
December 31, 2019			
Current assets	$ 442,291	$ (442,291)	$ —
Other assets	280,397	(280,397)	—
Current liabilities	(444,188)	442,291	(1,897)
Long-term liabilities	(282,381)	280,397	(1,984)
Total	$ (3,881)	$ —	$ (3,881)
December 31, 2018			
Current assets	$ 53,136	$ (3,207)	$49,929
Current liabilities	(3,207)	3,207	—
Long-term liabilities	(83)	—	(83)
Total	$ 49,846	$ —	$49,846

NOTE 12 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following table summarizes the location and aggregate gain (loss) of all derivative financial instruments recorded in the consolidated statements of operations for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

Type of Instrument	Location in Statement of Operations	Year Ended December 31, 2019	2018	2017
Derivative Instrument				
Oil	Revenues: Realized gain (loss) on derivatives	$ 9,026	$ 3,741	$(3,657)
Natural Gas	Revenues: Realized gain (loss) on derivatives	456	(1,407)	(608)
NGLs	Revenues: Realized loss on derivatives	—	—	(56)
Realized gain (loss) on derivatives		9,482	2,334	(4,321)
Oil	Revenues: Unrealized (loss) gain on derivatives	(53,443)	65,991	2,638
Natural Gas	Revenues: Unrealized (loss) gain on derivatives	(284)	(906)	7,077
Unrealized (loss) gain on derivatives		(53,727)	65,085	9,715
Total		$(44,245)	$67,419	$ 5,394

NOTE 13 — FAIR VALUE MEASUREMENTS

The Company measures and reports certain financial and non-financial assets and liabilities on a fair value basis. Fair value is 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 (exit price). Fair value measurements are classified and disclosed in one of the following categories.

Level 1 Unadjusted quoted prices for identical, unrestricted assets or liabilities in active markets.

Level 2 Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that are valued with industry standard models that consider various inputs, including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3 Unobservable inputs that are not corroborated by market data that reflect a company's own market assumptions.

Financial and non-financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables summarize the valuation of the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of December 31, 2019 and 2018 (in thousands).

Description	Fair Value Measurements at December 31, 2019 using Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil derivatives and basis swaps	$ —	$(3,881)	$ —	$(3,881)
Total	$ —	$(3,881)	$ —	$(3,881)

NOTE 13 — FAIR VALUE MEASUREMENTS — Continued

	Fair Value Measurements at December 31, 2018 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil derivatives and basis swaps	$ —	$49,562	$ —	$49,562
Natural gas derivatives	—	284	—	284
Total	$ —	$49,846	$ —	$49,846

Additional disclosures related to derivative financial instruments are provided in Note 12.

Other Fair Value Measurements

At December 31, 2019 and 2018, the carrying values reported on the consolidated balance sheets for accounts receivable, prepaid expenses and other current assets, accounts payable, accrued liabilities, royalties payable, amounts due to affiliates, advances from joint interest owners, amounts due to joint ventures and other current liabilities approximate their fair values due to their short-term maturities.

At December 31, 2019, the carrying value of borrowings under the Credit Agreement and the San Mateo Credit Facility approximated their fair value as both are subject to short-term floating interest rates that reflect market rates available to the Company at the time and are classified at Level 2 in the fair value hierarchy.

At December 31, 2019 and 2018, the fair value of the Notes was $1.06 billion and $968.9 million, respectively, based on quoted market prices, which represent Level 1 inputs in the fair value hierarchy.

Certain assets and liabilities are measured at fair value on a nonrecurring basis, including assets and liabilities acquired in a business combination, lease and well equipment inventory when the market value is determined to be lower than the cost of the inventory and other property and equipment that are reduced to fair value when they are impaired or held for sale. The Company recorded no impairment to its lease and well equipment inventory or other property and equipment in 2019 and 2018.

NOTE 14 — COMMITMENTS AND CONTINGENCIES

Processing, Transportation and Salt Water Disposal Commitments

Firm Commitments

From time to time, the Company enters into agreements with third parties whereby the Company commits to deliver anticipated natural gas and oil production and salt water from certain portions of its acreage for gathering, transportation, processing, fractionation, sales and, in the case of salt water, disposal. The Company paid approximately $28.7 million and $20.6 million for deliveries under these agreements during the years ended December 31, 2019 and 2018, respectively. Certain of these agreements contain minimum volume commitments. If the Company does not meet the minimum volume commitments under these agreements, it will be required to pay certain deficiency fees. If the Company ceased operations in the areas subject to these agreements at December 31, 2019, the total deficiencies required to be paid by the Company under these agreements would be approximately $406.8 million, in addition to the commitments described below.

NOTE 14 — COMMITMENTS AND CONTINGENCIES — Continued

Future Commitments

In late 2017, the Company entered into a fixed-fee NGL sales agreement whereby the Company committed to deliver its NGL production at the tailgate of the Black River Processing Plant to a certain counterparty. The Company is committed to deliver a minimum amount of NGLs to the counterparty upon construction and completion of a pipeline extension and a fractionation facility by the counterparty, which is currently expected to be completed in 2020. The Company has no rights to compel the counterparty to construct this pipeline extension or fractionation facility. If the counterparty does not construct the pipeline extension and fractionation facility, then the Company does not have any minimum volume commitments under the agreement. If the counterparty constructs the pipeline extension and fractionation facility on or prior to February 28, 2021, then the Company will have a commitment to deliver a minimum amount of NGLs for seven years following the completion of the pipeline extension and fractionation facility. If the Company does not meet its NGL volume commitment in any quarter during the seven-year commitment period, it will be required to pay a deficiency fee per gallon of NGL deficiency. Should the pipeline extension and fractionation facility be completed on or prior to February 28, 2021, the minimum contractual obligation during the seven-year period would be approximately $132.3 million.

In October 2019, the Company entered into a 15-year, fixed-fee natural gas transportation agreement whereby the Company committed to deliver a portion of the residue gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline. The agreement begins when the counterparty's pipeline is placed in service, which is anticipated to be the third quarter of 2020. Should the pipeline be placed in service, the Company will owe the fees to transport the committed volume whether or not the committed volume is transported through the counterparty's pipeline, and the minimum contractual obligation would be approximately $106.9 million.

Delaware Basin — San Mateo

In February 2017, the Company dedicated its current and future leasehold interests in the Rustler Breaks and Wolf asset areas pursuant to 15-year, fixed-fee natural gas, oil and salt water gathering agreements and salt water disposal agreements with subsidiaries of San Mateo I. In addition, the Company dedicated its current and future leasehold interests in the Rustler Breaks asset area pursuant to a 15-year, fixed-fee natural gas processing agreement (collectively with the gathering and salt water disposal agreements, the "Operational Agreements"). San Mateo I provides the Company with firm service under each of the Operational Agreements in exchange for certain minimum volume commitments. The minimum contractual obligation under the Operational Agreements at December 31, 2019 was approximately $152.9 million.

In connection with the February 2019 formation of San Mateo II, the Company dedicated to San Mateo II acreage in the Greater Stebbins Area and the Stateline asset area pursuant to 15-year, fixed-fee agreements for oil, natural gas and salt water gathering, natural gas processing and salt water disposal (collectively, the "San Mateo II Operational Agreements"). San Mateo II provides the Company with firm service under each of the San Mateo II Operational Agreements in exchange for certain minimum volume commitments. The minimum contractual obligation under the San Mateo II Operational Agreements at inception was approximately $363.8 million and begins in 2020.

NOTE 14 — COMMITMENTS AND CONTINGENCIES — Continued

In June 2019, a subsidiary of San Mateo II entered into an agreement with third parties for the engineering, procurement, construction and installation of an expansion of the Black River Processing Plant, including required compression. The expansion is expected to be placed in service in 2020. San Mateo II's total commitments under this agreement are $80.4 million. San Mateo II paid approximately $40.1 million under this agreement during the year ended December 31, 2019. As of December 31, 2019, the remaining obligations under this agreement were $40.3 million, which are expected to be paid within the next year.

Other Commitments

The Company does not own or operate its own drilling rigs, but instead enters into contracts with third parties for such drilling rigs. These contracts establish daily rates for the drilling rigs and the term of the Company's commitment for the drilling services to be provided. The Company would incur a termination obligation if the Company elected to terminate a contract and if the drilling contractor were unable to secure replacement work for the contracted drilling rigs at the same daily rates being charged to the Company prior to the end of their respective contract terms. The Company's undiscounted minimum outstanding aggregate termination obligations under its drilling rig contracts were approximately $41.7 million at December 31, 2019, of which $1.2 million is related to short-term drilling rig contracts, which are not recorded on the consolidated balance sheet.

At December 31, 2019, the Company had outstanding commitments to participate in the drilling and completion of various non-operated wells. If all of these wells are drilled and completed as proposed, the Company's minimum outstanding aggregate commitments for its participation in these non-operated wells were approximately $26.9 million at December 31, 2019. The Company expects these costs to be incurred within the next year.

Legal Proceedings

The Company is a party to several legal proceedings encountered in the ordinary course of its business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, in the opinion of management, it is remote that these legal proceedings will have a material adverse impact on the Company's financial condition, results of operations or cash flows.

NOTE 15 — SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at December 31, 2019 and 2018 (in thousands).

	December 31,	
	2019	2018
Accrued evaluated and unproved and unevaluated property costs	$ 72,376	$ 86,318
Accrued midstream properties costs	46,402	16,808
Accrued lease operating expenses	18,223	12,705
Accrued interest on debt	18,569	22,448
Accrued asset retirement obligations	619	1,350
Accrued partners' share of joint interest charges	14,322	17,037
Accrued payable related to purchased natural gas	17,806	4,442
Other	12,378	9,747
Total accrued liabilities	$200,695	$170,855

NOTE 15 — SUPPLEMENTAL DISCLOSURES — Continued

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the years ended December 31, 2019, 2018 and 2017 (in thousands).

	Year Ended December 31,		
	2019	2018	2017
Cash paid for interest expense, net of amounts capitalized	$ 75,525	$ 29,474	$32,760
Increase in asset retirement obligations related to mineral properties	$ 2,912	$ 2,614	$ 4,385
Increase (decrease) in asset retirement obligations related to midstream properties	$ 1,204	$ 686	$ (60)
(Decrease) increase in liabilities for oil and natural gas properties capital expenditures	$(15,877)	$(16,802)	$48,929
Increase (decrease) in liabilities for midstream properties capital expenditures	$ 30,374	$ 2,499	$ (955)
Stock-based compensation expense (benefit) recognized as liability	$ 3,170	$ (1,069)	$ 362
Decrease in liabilities for accrued cost to issue equity	$ —	$ —	$ (343)
Increase in liabilities for accrued cost to issue senior notes	$ —	$ 232	$ —
Transfer of inventory from (to) oil and natural gas properties	$ 1,515	$ 409	$ (374)
Transfer of inventory to midstream properties	$ —	$ —	$ (317)

The following table provides a reconciliation of cash and restricted cash recorded in the consolidated balance sheets to cash and restricted cash as presented on the consolidated statements of cash flows (in thousands).

	Year Ended December 31,		
	2019	2018	2017
Cash	$40,024	$64,545	$ 96,505
Restricted cash	25,104	19,439	5,977
Total cash and restricted cash	$65,128	$83,984	$102,482

NOTE 16 — SEGMENT INFORMATION

The Company operates in two business segments: (i) exploration and production and (ii) midstream. The exploration and production segment is engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States and is currently focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company also operates in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana. The midstream segment conducts midstream operations in support of the Company's exploration, development and production operations and provides natural gas processing, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties. Substantially all of the Company's midstream operations in the Rustler Breaks and Wolf asset areas in the Delaware Basin are conducted through San Mateo (see Note 6).

NOTE 16 — SEGMENT INFORMATION — Continued

The following tables present selected financial information for the periods presented regarding the Company's business segments on a stand-alone basis, corporate expenses that are not allocated to a segment and the consolidation and elimination entries necessary to arrive at the financial information for the Company on a consolidated basis (in thousands). On a consolidated basis, midstream services revenues consist primarily of those revenues from midstream operations related to third parties, including working interest owners in the Company's operated wells. All midstream services revenues associated with Company-owned production are eliminated in consolidation. In evaluating the operating results of the exploration and production and midstream segments, the Company does not allocate certain expenses to the individual segments, including general and administrative expenses. Such expenses are reflected in the column labeled "Corporate."

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Year Ended December 31, 2019					
Oil and natural gas revenues	$ 886,127	$ 6,198	$ —	$ —	$ 892,325
Midstream services revenues	—	135,953	—	(76,843)	59,110
Sales of purchased natural gas	4,802	69,967	—	—	74,769
Lease bonus - mineral acreage	1,711	—	—	—	1,711
Realized gain on derivatives	9,482	—	—	—	9,482
Unrealized loss on derivatives	(53,727)	—	—	—	(53,727)
Expenses (1)	621,687	130,612	72,734	(76,843)	748,190
Operating income (loss) (2)	$ 226,708	$ 81,506	$(72,734)	$ —	$ 235,480
Total assets (3)	$3,360,725	$647,937	$ 61,014	$ —	$4,069,676
Capital expenditures (4)	$ 718,712	$223,612	$ 3,701	$ —	$ 946,025

(1) Includes depletion, depreciation and amortization expenses of $331.7 million and $16.1 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $2.7 million.

(2) Includes $35.2 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Excludes intercompany receivables and investments in subsidiaries.

(4) Includes $48.3 million attributable to land and seismic acquisition expenditures related to the exploration and production segment and $145.4 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Year Ended December 31, 2018					
Oil and natural gas revenues	$ 794,261	$ 6,439	$ —	$ —	$ 800,700
Midstream services revenues	—	86,737	—	(64,817)	21,920
Sales of purchased natural gas	902	6,169	—	—	7,071
Lease bonus - mineral acreage	2,489	—	—	—	2,489
Realized gain on derivatives	2,334	—	—	—	2,334
Unrealized gain on derivatives	65,085	—	—	—	65,085
Expenses (1)	487,539	44,098	69,508	(64,817)	536,328
Operating income (loss) (2)	$ 377,532	$ 55,247	$(69,508)	$ —	$ 363,271
Total assets (3)	$2,910,326	$439,953	$105,239	$ —	$3,455,518
Capital expenditures (4)	$1,335,690	$166,407	$ 2,562	$ —	$1,504,659

(1) Includes depletion, depreciation and amortization expenses of $252.3 million and $10.5 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $2.4 million.

(2) Includes $25.6 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Excludes intercompany receivables and investments in subsidiaries.

(4) Includes $656.9 million attributable to land and seismic acquisition expenditures related to the exploration and production segment and $80.2 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

NOTE 16 — SEGMENT INFORMATION — Continued

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Year Ended December 31, 2017					
Oil and natural gas revenues	$ 525,862	$ 2,822	$ —	$ —	$ 528,684
Midstream services revenues	—	47,037	—	(36,839)	10,198
Realized loss on derivatives	(4,321)	—	—	—	(4,321)
Unrealized gain on derivatives	9,715	—	—	—	9,715
Expenses (1)	333,923	23,420	62,931	(36,839)	383,435
Operating income (loss) (2)	$ 197,333	$ 26,439	$ (62,931)	$ —	$ 160,841
Total assets (3)	$1,768,393	$257,871	$119,426	$ —	$2,145,690
Capital expenditures (4)	$ 753,157	$114,113	$ 5,688	$ —	$ 872,958

(1) Includes depletion, depreciation and amortization expenses of $170.5 million and $5.2 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $1.7 million.

(2) Includes $12.1 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Excludes intercompany receivables and investments in subsidiaries.

(4) Includes $54.9 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

NOTE 17 — SUBSIDIARY GUARANTORS

The Notes are jointly and severally guaranteed by certain subsidiaries of Matador (the "Guarantor Subsidiaries") on a full and unconditional basis (except for customary release provisions). At December 31, 2019, the Guarantor Subsidiaries were 100% owned by Matador. Matador is a parent holding company and has no independent assets or operations, and there are no significant restrictions on the ability of Matador to obtain funds from the Guarantor Subsidiaries by dividend or loan. San Mateo and its subsidiaries (the "Non-Guarantor Subsidiaries") are not guarantors of the Notes.

NOTE 17 — SUBSIDIARY GUARANTORS — Continued

The following tables present condensed consolidating financial information of Matador (as issuer of the Notes), the Non-Guarantor Subsidiaries, the Guarantor Subsidiaries and all entities on a consolidated basis (in thousands). Elimination entries are necessary to combine the entities. This financial information is presented in accordance with the requirements of Rule 3-10 of Regulation S-X. The following financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities.

Condensed Consolidating Balance Sheet

	December 31, 2019				
	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
ASSETS					
Intercompany receivable	$1,578,133	$ 29,217	$ —	$(1,607,350)	$ —
Current assets	29	37,933	240,530	—	278,492
Net property and equipment	—	583,899	3,115,696	—	3,699,595
Investment in subsidiaries	1,332,237	—	144,697	(1,476,934)	—
Long-term assets	—	3,072	99,049	(10,532)	91,589
Total assets	$2,910,399	$654,121	$3,599,972	$(3,094,816)	$4,069,676
LIABILITIES AND EQUITY					
Intercompany payable	$ —	$ —	$1,607,350	$(1,607,350)	$ —
Current liabilities	—	73,086	327,595	(909)	399,772
Senior unsecured notes payable	1,039,416	—	—	—	1,039,416
Other long-term liabilities	37,329	300,540	332,790	(9,623)	661,036
Total equity attributable to Matador Resources Company	1,833,654	144,697	1,332,237	(1,476,934)	1,833,654
Non-controlling interest in subsidiaries	—	135,798	—	—	135,798
Total liabilities and equity	$2,910,399	$654,121	$3,599,972	$(3,094,816)	$4,069,676

Condensed Consolidating Balance Sheet

	December 31, 2018				
	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
ASSETS					
Intercompany receivable	$1,244,405	$ 29,816	$ —	$(1,274,221)	$ —
Current assets	4,109	34,027	267,549	—	305,685
Net property and equipment	—	379,052	2,743,812	—	3,122,864
Investment in subsidiaries	1,490,401	—	95,346	(1,585,747)	—
Long-term assets	23,897	1,479	11,095	(9,502)	26,969
Total assets	$2,762,812	$444,374	$3,117,802	$(2,869,470)	$3,455,518
LIABILITIES AND EQUITY					
Intercompany payable	$ —	$ —	$1,274,221	$(1,274,221)	$ —
Current liabilities	22,874	27,988	279,884	(724)	330,022
Senior unsecured notes payable	1,037,837	—	—	—	1,037,837
Other long-term liabilities	13,221	230,263	73,296	(8,778)	308,002
Total equity attributable to Matador Resources Company	1,688,880	95,346	1,490,401	(1,585,747)	1,688,880
Non-controlling interest in subsidiaries	—	90,777	—	—	90,777
Total liabilities and equity	$2,762,812	$444,374	$3,117,802	$(2,869,470)	$3,455,518

NOTE 17 — SUBSIDIARY GUARANTORS — Continued

Condensed Consolidating Statement of Operations

	For the Year Ended December 31, 2019				
	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$ —	$209,887	$848,502	$ (74,719)	$983,670
Total expenses	(1,458)	128,758	695,609	(74,719)	748,190
Operating (loss) income	1,458	81,129	152,893	—	235,480
Net loss on asset sales and inventory impairment	—	—	(967)	—	(967)
Interest expense	(64,591)	(9,282)	—	—	(73,873)
Other income (expense)	—	3	(2,129)	—	(2,126)
Earnings in subsidiaries	186,442	—	36,645	(223,087)	—
Income before income taxes	123,309	71,850	186,442	(223,087)	158,514
Total income tax provision	35,532	—	—	—	35,532
Net income attributable to non-controlling interest in subsidiaries	—	(35,205)	—	—	(35,205)
Net income attributable to Matador Resources Company shareholders	$ 87,777	$ 36,645	$186,442	$(223,087)	$ 87,777

Condensed Consolidating Statement of Operations

	For the Year Ended December 31, 2018				
	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$ —	$ 98,665	$865,725	$ (64,791)	$899,599
Total expenses	4,935	46,236	549,948	(64,791)	536,328
Operating (loss) income	(4,935)	52,429	315,777	—	363,271
Net loss on asset sales and inventory impairment	—	—	(196)	—	(196)
Interest expense	(40,994)	(333)	—	—	(41,327)
Prepayment penalty on extinguishment of debt	(31,226)	—	—	—	(31,226)
Other income	565	62	924	—	1,551
Earnings in subsidiaries	343,106	—	26,601	(369,707)	—
Income before income taxes	266,516	52,158	343,106	(369,707)	292,073
Total income tax benefit	(7,691)	—	—	—	(7,691)
Net income attributable to non-controlling interest in subsidiaries	—	(25,557)	—	—	(25,557)
Net income attributable to Matador Resources Company shareholders	$274,207	$ 26,601	$343,106	$(369,707)	$274,207

Condensed Consolidating Statement of Operations

	For the Year Ended December 31, 2017				
	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$ —	$ 47,883	$531,508	$ (35,115)	$544,276
Total expenses	5,610	21,260	391,680	(35,115)	383,435
Operating (loss) income	(5,610)	26,623	139,828	—	160,841
Net gain on asset sales and inventory impairment	—	—	23	—	23
Interest expense	(34,565)	—	—	—	(34,565)
Other income	27	37	3,487	—	3,551
Earnings in subsidiaries	157,589	—	14,251	(171,840)	—
Income before income taxes	117,441	26,660	157,589	(171,840)	129,850
Total income tax (benefit) provision	(8,426)	269	—	—	(8,157)
Net income attributable to non-controlling interest in subsidiaries	—	(12,140)	—	—	(12,140)
Net income attributable to Matador Resources Company shareholders	$125,867	$ 14,251	$157,589	$(171,840)	$125,867

NOTE 17 — SUBSIDIARY GUARANTORS — Continued

Condensed Consolidating Statement of Cash Flows

	For the Year Ended December 31, 2019				
	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$(427)	$ 106,650	$ 445,819	$ —	$ 552,042
Net cash used in investing activities	—	(188,893)	(698,455)	(16,628)	(903,976)
Net cash provided by financing activities	—	88,059	228,391	16,628	333,078
(Decrease) increase in cash and restricted cash	(427)	5,816	(24,245)	—	(18,856)
Cash and restricted cash at beginning of year	456	18,840	64,688	—	83,984
Cash and restricted cash at end of year	$ 29	$ 24,656	$ 40,443	$ —	$ 65,128

Condensed Consolidating Statement of Cash Flows

	For the Year Ended December 31, 2018				
	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$(657,860)	$ 35,119	$ 1,231,264	$ —	$ 608,523
Net cash used in investing activities	—	(162,147)	(1,310,776)	(42,330)	(1,515,253)
Net cash provided by financing activities	658,030	140,205	47,667	42,330	888,232
Increase (decrease) in cash and restricted cash	170	13,177	(31,845)	—	(18,498)
Cash and restricted cash at beginning of year	286	5,663	96,533	—	102,482
Cash and restricted cash at end of year	$ 456	$ 18,840	$ 64,688	$ —	$ 83,984

Condensed Consolidating Statement of Cash Flows

	For the Year Ended December 31, 2017				
	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$(307,982)	$ 21,308	$ 585,799	$ —	$ 299,125
Net cash provided by (used in) investing activities	33	(114,852)	(597,870)	(106,595)	(819,284)
Net cash provided by (used in) financing activities	208,440	96,307	(2,843)	106,595	408,499
Decrease (increase) in cash and restricted cash	(99,509)	2,763	(14,914)	—	(111,660)
Cash and restricted cash at beginning of year	99,795	2,900	111,447	—	214,142
Cash and restricted cash at end of year	$ 286	$ 5,663	$ 96,533	$ —	$ 102,482

MATADOR RESOURCES COMPANY AND SUBSIDIARIES
December 31, 2019, 2018 and 2017

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES

Costs Incurred

The following table summarizes costs incurred and capitalized by the Company in the acquisition, exploration and development of oil and natural gas properties for the years ended December 31, 2019, 2018 and 2017 (in thousands).

	Year Ended December 31,		
	2019	2018	2017
Property acquisition costs			
Proved	$ 3,767	$ 4,788	$ 45,270
Unproved and unevaluated	39,595	633,502	214,662
Exploration costs	109,439	229,974	167,213
Development costs	570,290	467,426	326,012
Total costs incurred (1)	$723,091	$1,335,690	$753,157

(1) Excludes midstream-related development and corporate costs of approximately $227.3 million, $169.0 million and $119.8 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Property acquisition costs are costs incurred to purchase, lease or otherwise acquire oil and natural gas properties, including both unproved and unevaluated leasehold and purchases of reserves in place. For the years ended December 31, 2019, 2018 and 2017, most of the Company's property acquisition costs resulted from the acquisition of unproved and unevaluated leasehold and mineral interests.

Exploration costs are costs incurred in identifying areas of these oil and natural gas properties that may warrant further examination and in examining specific areas that are considered to be prospective for oil and natural gas, including costs of drilling exploratory wells, geological and geophysical costs and costs of carrying and retaining unproved and unevaluated properties. Exploration costs may be incurred before or after acquiring the related oil and natural gas properties. For the years ended December 31, 2019, 2018 and 2017, the Company capitalized $2.9 million, $17.7 million and $1.8 million, respectively, of geological and geophysical costs, which are included as exploration costs in the table above.

Development costs are costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil and natural gas. Development costs include the costs of preparing well locations for drilling, drilling and equipping development wells and acquiring, constructing and installing production facilities.

Costs incurred also include newly established asset retirement obligations, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement obligations included in the table above were approximately $4.3 million, $4.0 million and $4.8 million for the years ended December 31, 2019, 2018 and 2017, respectively. Capitalized general and administrative expenses that are directly related to acquisition, exploration and development activities are also included in the table above. The Company capitalized $31.1 million, $29.9 million and $23.1 million of these internal costs for the years ended December 31, 2019, 2018 and 2017, respectively, excluding midstream-related capitalized general and administrative expenses. Capitalized interest expense for qualifying projects is also included in the table above. The Company capitalized $7.6 million, $8.8 million and $7.3 million of its interest expense for the years ended December 31, 2019, 2018 and 2017, respectively.

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

Oil and Natural Gas Reserves

Proved reserves are estimated quantities of oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs using existing economic and operating conditions. Estimating oil and natural gas reserves is complex and inexact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of both the data and the associated interpretations of that data can vary. The process also requires certain economic assumptions, including, but not limited to, oil and natural gas prices, drilling, completion and operating expenses, capital expenditures and taxes. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas most likely will vary from the Company's estimates.

The Company reports its production and proved reserves in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where the Company produces liquids-rich natural gas, such as in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas and the Eagle Ford shale in South Texas, the economic value of the NGLs associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the NGLs are extracted and sold. The Company's oil and natural gas reserves estimates for the years ended December 31, 2019, 2018 and 2017 were prepared by the Company's engineering staff in accordance with guidelines established by the SEC and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

Oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. The commodity prices used to estimate oil and natural gas reserves are based on unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period. For the period from January through December 2019, these average oil and natural gas prices were $52.19 per Bbl and $2.58 per MMBtu, respectively. For the period from January through December 2018, these average oil and natural gas prices were $62.04 per Bbl and $3.10 per MMBtu, respectively. For the period from January through December 2017, these average oil and natural gas prices were $47.79 per Bbl and $2.98 per MMBtu, respectively.

The Company's net ownership in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves are summarized as follows. All of the Company's oil and natural gas reserves are attributable to properties located in the United States. The estimated reserves shown below are proved reserves only and do not include any value for unproved reserves classified as probable or possible reserves that might exist for these properties, nor do they include any consideration that could be attributed to interests in unevaluated acreage beyond those tracts for which reserves have been estimated. In the tables presented throughout this section, natural gas is converted to oil equivalent using the ratio of one Bbl of oil to six Mcf of natural gas.

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

	Net Proved Reserves		
	Oil	Natural Gas	Oil Equivalent
	(MBbl)	(MMcf)	(MBOE)
Total at December 31, 2016	56,977	292,649	105,752
Revisions of prior estimates	3,847	34,395	9,580
Purchases of minerals in-place	5,257	7,348	6,482
Extensions and discoveries	28,513	99,935	45,169
Production	(7,851)	(38,163)	(14,212)
Total at December 31, 2017	86,743	396,164	152,771
Revisions of prior estimates	5,908	32,497	11,326
Purchases of minerals-in-place	446	900	596
Extensions and discoveries	41,445	169,224	69,646
Production	(11,141)	(47,311)	(19,026)
Total at December 31, 2018	123,401	551,474	215,313
Revisions of prior estimates	(605)	34,062	5,073
Net divestitures of minerals-in-place	(298)	(12,048)	(2,307)
Extensions and discoveries	39,477	114,833	58,616
Production	(13,984)	(61,083)	(24,164)
Total at December 31, 2019	147,991	627,238	252,531
Proved Developed Reserves			
December 31, 2016	22,604	126,759	43,731
December 31, 2017	36,966	190,109	68,651
December 31, 2018	53,223	246,229	94,261
December 31, 2019	59,667	276,258	105,710
Proved Undeveloped Reserves			
December 31, 2016	34,373	165,890	62,021
December 31, 2017	49,777	206,055	84,120
December 31, 2018	70,178	305,245	121,052
December 31, 2019	88,324	350,980	146,821

The following is a discussion of the changes in the Company's proved oil and natural gas reserves estimates for the years ended December 31, 2019, 2018 and 2017.

The Company's proved oil and natural gas reserves increased to 252,531 MBOE at December 31, 2019 from 215,313 MBOE at December 31, 2018. The Company's proved oil and natural gas reserves increased by 61,382 MBOE and the Company produced 24,164 MBOE during the year ended December 31, 2019, resulting in a net increase of 37,218 MBOE. The Company's proved oil and natural gas reserves increased by 58,616 MBOE during 2019 as a result of extensions and discoveries during the year, which were primarily attributable to drilling operations in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company's proved oil and natural gas reserves increased by 5,073 MBOE during 2019 as a result of revisions of prior estimates, which were attributable to better-than-projected well performance from certain wells, but which were offset by lower weighted average oil and natural gas prices used to estimate proved reserves in 2019, as compared to 2018. The Company's proved oil and natural gas reserves decreased by 2,307 MBOE in 2019 as a result of net divestitures of minerals-in-place primarily in the Eagle Ford shale in South Texas and the Haynesville shale in Northwest Louisiana. The Company's proved developed oil and natural gas reserves increased to 105,710 MBOE at December 31, 2019 from 94,261 MBOE at December 31, 2018, primarily due to proved developed reserves added as a result of drilling operations in the Wolfcamp and Bone Spring plays in the Delaware Basin. At December 31, 2019, the Company's proved reserves were made up of approximately 59% oil and 41% natural gas and were approximately 42% proved developed and approximately 58% proved undeveloped.

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

The Company's proved oil and natural gas reserves increased to 215,313 MBOE at December 31, 2018 from 152,771 MBOE at December 31, 2017. The Company's proved oil and natural gas reserves increased by 81,568 MBOE and the Company produced 19,026 MBOE during the year ended December 31, 2018, resulting in a net increase of 62,542 MBOE. The Company's proved oil and natural gas reserves increased by 69,646 MBOE as a result of extensions and discoveries during the year, which were primarily attributable to drilling operations in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company's proved oil and natural gas reserves increased by 11,326 MBOE during 2018 as a result of revisions of prior estimates, which were attributable to better-than-projected well performance from certain wells and higher weighted average oil and natural gas prices used to estimate proved reserves in 2018, as compared to 2017. The Company also added 596 MBOE in proved oil and natural gas reserves in 2018 as a result of purchases of minerals-in-place in the Delaware Basin. The Company's proved developed oil and natural gas reserves increased to 94,261 MBOE at December 31, 2018 from 68,651 MBOE at December 31, 2017, primarily due to proved developed reserves added as a result of drilling operations in the Wolfcamp and Bone Spring plays in the Delaware Basin. At December 31, 2018, the Company's proved reserves were made up of approximately 57% oil and 43% natural gas and were approximately 44% proved developed and approximately 56% proved undeveloped.

The Company's proved oil and natural gas reserves increased to 152,771 MBOE at December 31, 2017 from 105,752 MBOE at December 31, 2016. The Company's proved oil and natural gas reserves increased by 61,231 MBOE and the Company produced 14,212 MBOE during the year ended December 31, 2017, resulting in a net increase of 47,019 MBOE. The Company's proved oil and natural gas reserves increased by 45,169 MBOE as a result of extensions and discoveries during the year, which were primarily attributable to drilling operations in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company's proved oil and natural gas reserves increased by 9,580 MBOE during 2017 as a result of revisions of prior estimates, which were attributable to better-than-projected well performance from certain wells and higher weighted average oil and natural gas prices used to estimate proved reserves in 2017, as compared to 2016. The Company also added 6,482 MBOE in proved oil and natural gas reserves in 2017 as a result of purchases of minerals-in-place in the Delaware Basin. The Company's proved developed oil and natural gas reserves increased to 68,651 MBOE at December 31, 2017 from 43,731 MBOE at December 31, 2016, primarily due to proved developed reserves added as a result of drilling operations in the Wolfcamp and Bone Spring plays in the Delaware Basin. At December 31, 2017, the Company's proved reserves were made up of approximately 57% oil and 43% natural gas and were approximately 45% proved developed and approximately 55% proved undeveloped.

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

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is not intended to provide an estimate of the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair market value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, potential improvements in industry technology and operating practices, the risks inherent in reserves estimates and perhaps different discount rates.

As noted previously, for the period from January through December 2019, the unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices were $52.19 per Bbl and $2.58 per MMBtu, respectively. For the period from January through December 2018, the comparable average oil and natural gas prices were $62.04 per Bbl and $3.10 per MMBtu, respectively. For the period from January through December 2017, the comparable average oil and natural gas prices were $47.79 per Bbl and $2.98 per MMBtu, respectively.

Future net cash flows were computed by applying these oil and natural gas prices, adjusted for all associated transportation and gathering costs, gravity and energy content and regional price differentials, to year-end quantities of proved oil and natural gas reserves and accounting for any future production and development costs associated with producing these reserves; neither prices nor costs were escalated with time in these computations.

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

Future income taxes were computed by applying the statutory tax rate to the excess of future net cash flows relating to proved oil and natural gas reserves less the tax basis of the associated properties. Tax credits and net operating loss carryforwards available to the Company were also considered in the computation of future income taxes. Future net cash flows after income taxes were discounted using a 10% annual discount rate to derive the standardized measure of discounted future net cash flows.

The following table presents the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for the years ended December 31, 2019, 2018 and 2017 (in thousands).

	Year Ended December 31,		
	2019	2018	2017
Future cash inflows	$ 8,771,595	$ 8,822,004	$ 5,249,116
Future production costs	(3,087,142)	(2,713,043)	(1,759,495)
Future development costs	(1,638,744)	(1,384,916)	(1,029,105)
Future income tax expense	(479,011)	(710,222)	(228,622)
Future net cash flows	3,566,698	4,013,823	2,231,894
10% annual discount for estimated timing of cash flows	(1,532,715)	(1,763,210)	(973,248)
Standardized measure of discounted future net cash flows	$ 2,033,983	$ 2,250,613	$ 1,258,646

The following table summarizes the changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for the years ended December 31, 2019, 2018 and 2017 (in thousands).

	Year Ended December 31,		
	2019	2018	2017
Balance, beginning of period	$2,250,613	$1,258,646	$ 575,043
Net change in sales and transfer prices and in production (lifting) costs related to future production	(622,710)	574,381	374,370
Changes in estimated future development costs	(284,748)	(347,038)	(298,504)
Sales and transfers of oil and natural gas produced during the period	(682,747)	(631,596)	(403,095)
Net (divestitures) purchases of reserves in place	(28,849)	9,227	97,225
Net change due to extensions and discoveries	733,208	1,078,935	677,681
Net change due to revisions in estimates of reserves quantities	63,436	175,440	143,749
Previously estimated development costs incurred during the period	258,593	279,799	151,974
Accretion of discount	237,548	103,085	54,623
Other	(4,861)	3,600	(3,929)
Net change in income taxes	114,500	(253,866)	(110,491)
Standardized measure of discounted future net cash flows	$2,033,983	$2,250,613	$1,258,646

SELECTED QUARTERLY FINANCIAL INFORMATION

The following table presents selected unaudited quarterly financial information for 2019 (in thousands, except per share data).

	December 31	September 30	June 30	March 31
2019				
Oil and natural gas revenues	$258,619	$229,377	$211,060	$193,269
Third-party midstream services revenues	17,656	15,257	14,359	11,838
Sales of purchased gas	34,711	19,864	8,963	11,231
Lease bonus - mineral acreage	—	1,711	—	—
Realized gain on derivatives	1,701	3,346	1,165	3,270
Unrealized (loss) gain on derivatives	(24,012)	9,847	6,157	(45,719)
Expenses	223,627	193,300	164,915	166,348
Other expense	(21,209)	(18,859)	(18,859)	(18,039)
Income (loss) before income taxes	43,839	67,243	57,930	(10,498)
Income tax provision (benefit)	10,197	13,490	12,858	(1,013)
Net income (loss)	33,642	53,753	45,072	(9,485)
Net income attributable to non-controlling interest in subsidiaries	(9,623)	(9,800)	(8,320)	(7,462)
Net income (loss) attributable to Matador Resources Company shareholders	$ 24,019	$ 43,953	$ 36,752	$ (16,947)
Earnings (loss) per common share				
Basic	$ 0.21	$ 0.38	$ 0.32	$ (0.15)
Diluted	$ 0.21	$ 0.38	$ 0.31	$ (0.15)

The following table presents selected unaudited quarterly financial information for 2018 (in thousands, except per share data).

	December 31	September 30	June 30	March 31
2018				
Oil and natural gas revenues	$193,445	$216,282	$209,019	$181,954
Third-party midstream services revenues	8,636	6,809	3,407	3,068
Sales of purchased gas	7,071	—	—	—
Lease bonus - mineral acreage	2,489	—	—	—
Realized gain (loss) on derivatives	3,656	5,424	(2,488)	(4,258)
Unrealized gain (loss) on derivatives	74,577	(21,337)	1,429	10,416
Expenses	141,811	139,325	137,374	117,818
Other expense	(11,666)	(42,738)	(8,356)	(8,438)
Income before income taxes	136,397	25,115	65,637	64,924
Income tax benefit	(7,691)	—	—	—
Net income	144,088	25,115	65,637	64,924
Net income attributable to non-controlling interest in subsidiaries	(7,375)	(7,321)	(5,831)	(5,030)
Net income attributable to Matador Resources Company shareholders	$136,713	$ 17,794	$ 59,806	$ 59,894
Earnings per common share				
Basic	$ 1.18	$ 0.15	$ 0.53	$ 0.55
Diluted	$ 1.17	$ 0.15	$ 0.53	$ 0.55

Exhibit 31.1

CERTIFICATION

I, Joseph Wm. Foran, certify that:

1. I have reviewed this annual report on Form 10-K of Matador Resources Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 2, 2020

/s/ Joseph Wm. Foran

Joseph Wm. Foran
Chairman and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, David E. Lancaster, certify that:

1. I have reviewed this annual report on Form 10-K of Matador Resources Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 2, 2020

/s/ David E. Lancaster

David E. Lancaster
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

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

In connection with the annual report of Matador Resources Company (the "Company") on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, Joseph Wm. Foran, Chairman and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 2, 2020

/s/ Joseph Wm. Foran

Joseph Wm. Foran
Chairman and Chief Executive Officer
(Principal Executive Officer)

Exhibit 32.2

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

In connection with the annual report of Matador Resources Company (the "Company") on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, David E. Lancaster, Executive Vice President and Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 2, 2020

/s/ David E. Lancaster

David E. Lancaster
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

ADJUSTED EBITDA RECONCILIATION

This annual report includes the non-GAAP financial measure of Adjusted EBITDA. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of the Company's consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. "GAAP" means Generally Accepted Accounting Principles in the United States of America. The Company believes Adjusted EBITDA helps it evaluate its operating performance and compare its results of operations from period to period without regard to its financing methods or capital structure. The Company defines Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, net gain or loss on asset sales and inventory impairment and prepayment premium on extinguishment of debt. Adjusted EBITDA is not a measure of net income (loss) or net cash provided by operating activities as determined by GAAP.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss) or net cash provided by operating activities as determined in accordance with GAAP or as a primary indicator of the Company's operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following table presents the calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively, that are of a historical nature.

	Year Ended December 31,									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(In thousands)										
Unaudited Adjusted EBITDA reconciliation to Net Income (Loss):										
Net income (loss) attributable to Matador Resources Company shareholders	$ 6,377	$(10,309)	$ (33,261)	$ 45,094	$110,771	$(679,785)	$ (97,421)	$125,867	$274,207	$ 87,777
Net (loss) income attributable to non-controlling interest in subsidiaries	—	—	—	—	(17)	261	364	12,140	25,557	35,205
Net income (loss)	$ 6,377	$(10,309)	$ (33,261)	$ 45,094	$110,754	$(679,524)	$ (97,057)	$138,007	$299,764	$122,982
Interest expense	3	683	1,002	5,687	5,334	21,754	28,199	34,565	41,327	73,873
Total income tax provision (benefit)	3,521	(5,521)	(1,430)	9,697	64,375	(147,368)	(1,036)	(8,157)	(7,691)	35,532
Depletion, depreciation and amortization	15,596	31,754	80,454	98,395	134,737	178,847	122,048	177,502	265,142	350,540
Accretion of asset retirement obligations	155	209	256	348	504	734	1,182	1,290	1,530	1,822
Full-cost ceiling impairment	—	35,673	63,475	21,229	—	801,166	158,633	—	—	—
Unrealized (gain) loss on derivatives	(3,139)	(5,138)	4,802	7,232	(58,302)	39,265	41,238	(9,715)	(65,085)	53,727
Stock-based compensation expense	898	2,406	140	3,897	5,524	9,450	12,362	16,654	17,200	18,505
Net loss (gain) on asset sales and inventory impairment	224	154	485	192	0	(908)	(107,277)	(23)	196	967
Prepayment premium on extinguishment of debt	—	—	—	—	—	—	—	—	31,226	—
Consolidated Adjusted EBITDA	23,635	49,911	115,923	191,771	262,926	223,416	158,292	350,123	583,609	657,948
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	—	—	—	—	17	(278)	(400)	(14,060)	(30,386)	(47,192)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$23,635	$ 49,911	$115,923	$191,771	$262,943	$ 223,138	$ 157,892	$336,063	$553,223	$610,756

	Year Ended December 31,									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
(In thousands)										
Unaudited Adjusted EBITDA reconciliation to Net Cash Provided by Operating Activities:										
Net cash provided by operating activities	$27,273	$ 61,868	$124,228	$179,470	$251,481	$ 208,535	$ 134,086	$299,125	$608,523	$552,042
Net change in operating assets and liabilities	(2,230)	(12,594)	(9,307)	6,210	5,978	(8,980)	(1,809)	25,058	(64,429)	34,517
Interest expense, net of non-cash portion	3	683	1,002	5,687	5,334	20,902	27,051	34,097	39,970	71,389
Current income tax provision (benefit)	(1,411)	(46)	—	404	133	2,959	(1,036)	(8,157)	(455)	—
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	—	—	—	—	17	(278)	(400)	(14,060)	(30,386)	(47,192)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$23,635	$ 49,911	$115,923	$191,771	$262,943	$ 223,138	$ 157,892	$336,063	$553,223	$610,756

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CORPORATE INFORMATION

STOCK EXCHANGE LISTING

New York Stock Exchange (NYSE): MTDR

CORPORATE HEADQUARTERS

Matador Resources Company
One Lincoln Centre
5400 LBJ Freeway, Suite 1500
Dallas, Texas 75240
(972) 371-5200

For more information, please visit www.matadorresources.com.

For Employment Opportunities, please visit

www.matadorresources.com/careers
Email: careers@matadorresources.com

STOCK TRANSFER AGENT AND REGISTRAR

Please direct general questions about shareholder accounts, stock certificates, transfer of shares or duplicate mailings to Matador Resources Company's transfer agent:

Computershare Investor Services
462 South 4th Street, Suite 1600
Louisville, KY 40202
(800) 368-5948

www.computershare.com

FINANCIAL INFORMATION REQUESTS

To receive additional copies of our Annual Report on Form 10-K as filed with the SEC or to obtain other Matador Resources Company information, please contact Mac Schmitz, Capital Markets Coordinator, at our corporate headquarters.

Email: investors@matadorresources.com

OFFICER CERTIFICATIONS

Our Annual Report on Form 10-K filed with the SEC is included herein, excluding all exhibits other than our Sarbanes-Oxley Act Section 302 and 906 certifications by the CEO and CFO. We will send shareholders copies of the exhibits to our Annual Report on Form 10-K and any of our corporate governance documents, free of charge, upon request.

Note that these documents, along with further information about our history, board of directors, management team, operations and contact details, are available on our website at www.matadorresources.com.

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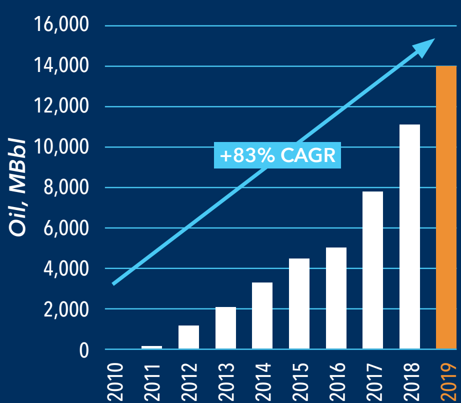
FORWARD-LOOKING STATEMENTS:

This annual report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. "Forward-looking statements" are statements related to future, not past, events. Forward-looking statements are based on current expectations and include any statement that does not directly relate to a current or historical fact. In this context, forward-looking statements often address expected future business and financial performance, and often contain words such as "could," "believe," "would," "anticipate," "intend," "estimate," "expect," "may," "should," "continue," "plan," "predict," "potential," "project," "hypothetical," "forecasted" and similar expressions that are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Such forward-looking statements include, but are not limited to, statements about guidance, projected or forecasted financial and operating results, future liquidity, results in certain basins, objectives, project timing, expectations and intentions, regulatory and governmental actions and other statements that are not historical facts. Actual results and future events could differ materially from those anticipated in such statements, and such forward-looking statements may not prove to be accurate. These forward-looking statements involve certain risks and uncertainties, including, but not limited to, the following risks related to financial and operational performance: general economic conditions; the Company's ability to execute its business plan, including whether its drilling program is successful; changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids; its ability to replace reserves and efficiently develop current reserves; costs of operations; delays and other difficulties related to producing oil, natural gas and natural gas liquids; delays and other difficulties related to regulatory and governmental approvals and restrictions; its ability to make acquisitions on economically acceptable terms; its ability to integrate acquisitions; availability of sufficient capital to execute its business plan, including from future cash flows, increases in its borrowing base and otherwise; weather and environmental conditions; the operating results of the Company's midstream joint venture's expansion of the Black River cryogenic processing plant, including the timing of the further expansion of such plant; the timing and operating results of the buildout by the Company's midstream joint venture of oil, natural gas and water gathering and transportation systems and the drilling of any additional salt water disposal wells, including in conjunction with the expansion of the midstream joint venture's services and assets into new areas in Eddy County, New Mexico; and other important factors which could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. For further discussions of risks and uncertainties, you should refer to Matador's filings with the Securities and Exchange Commission ("SEC"), including the "Risk Factors" section of Matador's Annual Report on Form 10-K enclosed herein. Matador undertakes no obligation to update these forward-looking statements to reflect events or circumstances occurring after the date of this annual report, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this annual report. All forward-looking statements are qualified in their entirety by this cautionary statement.

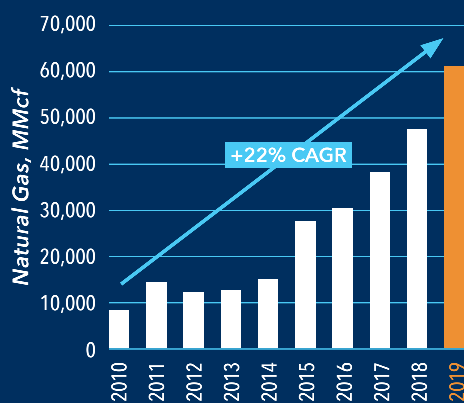
PROFITABLE GROWTH

AT A MEASURED PACE

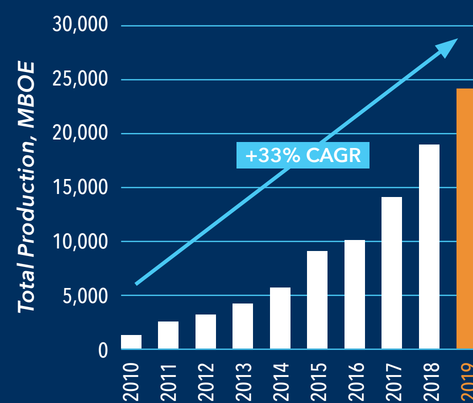
OIL PRODUCTION GROWTH



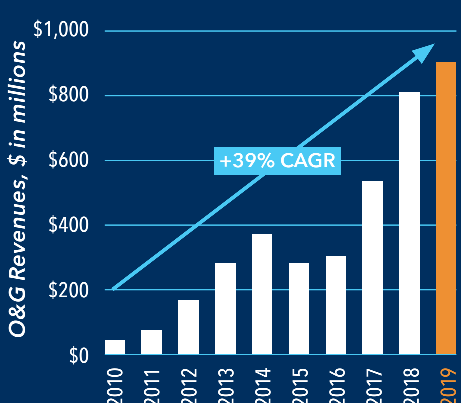
GAS PRODUCTION GROWTH



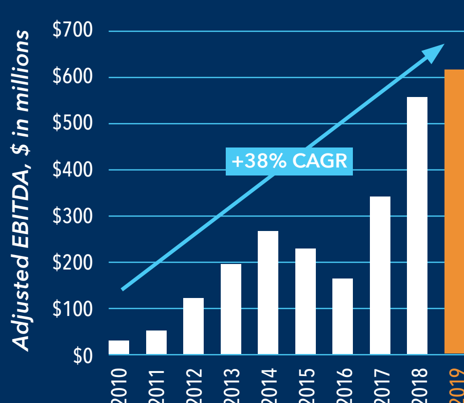
TOTAL PRODUCTION GROWTH



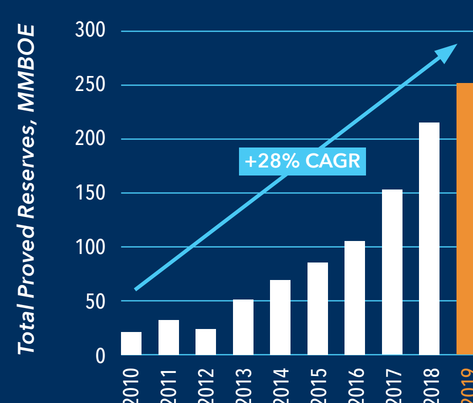
OIL AND GAS REVENUES GROWTH



ADJUSTED EBITDA GROWTH



OIL AND GAS RESERVES GROWTH



Note: CAGR is Compounded Annual Growth Rate.

Matador RESOURCES COMPANY

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