Matador Resources Co
Form 10-K
March 01, 2019
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
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
001-34574
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 75240 (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	Name of each exchange on which registered
Common Stock, par value $0.01 per share	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 ý 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 ý
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 ý 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 ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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	ý	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 ý

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 $3,305,546,848.

As of February 26, 2019, there were 116,388,317 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 2019 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.

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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, 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, changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids, the success of our drilling program, the timing of planned capital expenditures, the sufficiency of our cash flow from operations together with available borrowing capacity under our credit facilities, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to our properties and capacity of transportation facilities, availability of acquisitions, our ability to integrate acquisitions with our business, weather and environmental conditions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, 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.

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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, references to "we," "our" or the "Company" refer to Matador Resources Company and its subsidiaries as a whole (unless the context indicates otherwise) and references to "Matador" refer solely to Matador Resources Company. 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 and East Texas. Additionally, we conduct midstream operations, primarily through our midstream joint venture, San Mateo Midstream, LLC ("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 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, the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas;
- 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 2018 led to significant increases in our oil and natural gas production and proved oil and natural gas reserves. We also continued to increase our leasehold and minerals position in the Delaware Basin, in particular through the BLM Acquisition (as defined below). In addition, we concluded several important financing transactions in 2018, including the May 2018 public

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offering of 7,000,000 shares of our common stock, the refinancing and issuance of senior unsecured notes and two increases in the borrowing base under our Credit Agreement (as defined below). San Mateo also achieved several important milestones in 2018, including the completion and successful start-up of the expansion of the Black River Processing Plant (as defined below), the formation of a strategic relationship between a subsidiary of San Mateo and a subsidiary of Plains All American Pipeline, L.P. ("Plains") to gather and transport crude oil for us and third-party customers in and around the Rustler Breaks asset area, the completion and start-up of the Rustler Breaks Oil Pipeline System (as defined below), the addition of several significant third-party customers for salt water gathering and disposal and natural gas gathering and processing and the closing of the San Mateo Credit Facility (as defined below). These achievements and transactions increased our operational flexibility and opportunities while preserving the strength of our balance sheet and our liquidity position.

2018 Highlights

Increased Oil, Natural Gas and Oil Equivalent Production

For the year ended December 31, 2018, we achieved record oil, natural gas and average daily oil equivalent production. In 2018, we produced 11.1 million Bbl of oil, an increase of 42%, as compared to 7.9 million Bbl of oil produced in 2017. We also produced 47.3 Bcf of natural gas, an increase of 24% from 38.2 Bcf of natural gas produced in 2017. Our average daily oil equivalent production for the year ended December 31, 2018 was 52,128 BOE per day, including 30,524 Bbl of oil per day and 129.6 MMcf of natural gas per day, an increase of 34%, as compared to 38,936 BOE per day, including 21,510 Bbl of oil per day and 104.6 MMcf of natural gas per day, for the year ended December 31, 2017. The increase in oil and natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin throughout 2018, which offset declining production in the Eagle Ford and Haynesville shales where we have significantly reduced our operated activity since late 2014 and early 2015. Oil production comprised 59% 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, 2018, as compared to 55% for the year ended December 31, 2017.

Increased Oil, Natural Gas and Oil Equivalent Reserves

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, an increase of 41% from 152.8 million BOE, including 86.7 million Bbl of oil and 396.2 Bcf of natural gas, at December 31, 2017. The associated Standardized Measure and PV-10 of our estimated total proved oil and natural gas reserves increased 79% and 93% to $2.25 billion and $2.58 billion, respectively, at December 31, 2018, from $1.26 billion and $1.33 billion, respectively, at December 31, 2017, primarily as a result of our ongoing delineation and development drilling activities in the Delaware Basin during 2018 and higher weighted average oil and natural gas prices used to estimate proved reserves. 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 42% to 123.4 million Bbl at December 31, 2018 from 86.7 million Bbl at December 31, 2017. Our proved natural gas reserves increased 39% to 551.5 Bcf at December 31, 2018 from 396.2 Bcf at December 31, 2017. This growth in oil and natural gas reserves was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin during 2018.

At December 31, 2018, proved developed reserves included 53.2 million Bbl of oil and 246.2 Bcf of natural gas, and proved undeveloped reserves included 70.2 million Bbl of oil and 305.2 Bcf of natural gas. 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. Proved developed reserves and proved oil reserves comprised 45% and 57%, respectively, of our total proved oil and natural gas reserves at December 31, 2017.

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 five years. We expect the Delaware Basin will continue to be our primary area of focus in 2019.

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We completed and began producing oil and natural gas from 141 gross (73.8 net) wells in the Delaware Basin in 2018, including 82 gross (66.8 net) operated and 59 gross (7.0 net) non-operated wells. We also added to and upgraded our acreage position in the Delaware Basin during 2018. As a result, at December 31, 2018, our total acreage position in the Delaware Basin had increased to approximately 222,200 gross (132,000 net) acres, primarily in Loving County, Texas and Lea and Eddy Counties, New Mexico. We have focused our Delaware Basin operations thus far on our seven main 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 54% 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, as compared to 29,463 BOE per day (76% of total oil equivalent production), including 18,023 Bbl of oil per day (84% of total oil production) and 68.6 MMcf of natural gas per day (66% of total natural gas production), in 2017. We expect our Delaware Basin production to increase in 2019 as we continue the delineation and development of these asset areas.
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 2018 included:

- in our Rustler Breaks asset area, the results from the David Edelstein State Com 12&11-24S-27E RB #203H well, our first operated two-mile horizontal well, the performance of our Wolfcamp A-XY completions moving to the northwest region of the asset area, positive tests of the Second Bone Spring formation and the continued delineation and development of previously tested horizons;
- in our Wolf asset area, the results from several wells with longer laterals (greater than one mile) drilled and completed in the Wolfcamp A-XY interval in the southern portion of the asset area;
- 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 Second and Third Bone Spring completions, particularly in the SST and Stebbins acreage blocks in the Arrowhead asset area, and results from the recently completed Verna Rae Federal #204H well in the Ranger asset area, whose 24-hour initial potential ("IP") test results and subsequent well performance demonstrate the potential prospectivity of the Wolfcamp formation moving north in the Delaware Basin;
- in our Antelope Ridge asset area, the testing of six distinct intervals during 2018, including the Brushy Canyon, First, Second and Third Bone Spring, Wolfcamp A-XY and Wolfcamp A-Lower; and
- the significant progress made in our midstream operations, including (i) the completion and successful startup of the expansion of San Mateo's Black River cryogenic natural gas processing plant in the Rustler Breaks asset area (the "Black River Processing Plant") to a designed inlet capacity of 260 MMcf of natural gas per day, (ii) the completion of a natural gas liquids ("NGL") pipeline connection at the Black River Processing Plant to the NGL pipeline owned by EPIC Y-Grade Pipeline LP, (iii) the ongoing buildout of oil, natural gas and water pipeline systems in both the Rustler Breaks and Wolf asset areas, (iv) the entrance into a strategic relationship with Plains to gather and transport crude oil in the Rustler Breaks asset area, (v) placing into service crude oil gathering and transportation systems in the Wolf and Rustler Breaks asset areas, (vi) entering into long-term agreements with significant producers in Eddy County, New Mexico relating to the gathering and disposal of one such producer's salt water and the gathering and processing of another such producer's natural gas production and (vii) the drilling and completion of additional commercial salt water disposal wells and the construction of associated commercial facilities in the Rustler Breaks asset area, significantly increasing San Mateo's salt water disposal capacity.

We also completed and began producing oil and natural gas from four gross (1.5 net) wells in the Eagle Ford shale in South Texas in 2018, including one gross (1.0 net) operated and three gross (0.5 net) non-operated wells. We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana and East Texas during 2018, although we did participate in the drilling and completion of eight gross (0.2 net) non-operated Haynesville shale wells that began producing in 2018.
Financing Arrangements

We concluded several important financing transactions in 2018 that increased our operational flexibility and opportunities, while preserving the strength of our balance sheet and improving our liquidity position. These transactions included:

- the completion of a public offering of 7,000,000 shares of our common stock, whereby we received net proceeds of approximately $226.4 million;
- a series of transactions whereby we (i) issued $1.05 billion aggregate principal amount of senior notes and received net proceeds of $1.04 billion, (ii) redeemed $575.0 million aggregate principal amount of senior notes, (iii) improved the coupon rate on our senior notes outstanding to 5.875% from 6.875% and (iv) extended the maturity date of our senior notes from 2023 to 2026;

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- the amendment of our third amended and restated credit agreement (the “Credit Agreement”) to, among other items, (i) increase the maximum facility amount to $1.5 billion, (ii) increase the borrowing base to $850.0 million, (iii) increase the elected borrowing commitment to $500.0 million, (iv) extend the maturity to October 31, 2023, (v) reduce borrowing rates by 0.25% per annum and (vi) set the maximum leverage ratio at 4.00 to 1.00; and
- San Mateo’s entrance into a $250.0 million credit facility led by The Bank of Nova Scotia, as administrative agent (the “San Mateo Credit Facility”), and the cash distribution of $195.0 million, which was distributed 51% to us and 49% to our partner.

See “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources” for additional information regarding these financing arrangements.

BLM Acquisition

On September 12, 2018, we announced the successful acquisition of 8,400 gross and net leasehold acres in Lea and Eddy Counties, New Mexico for approximately $387 million, or a weighted average cost of approximately $46,000 per net acre, in the Bureau of Land Management (the “BLM”) New Mexico Oil and Gas Lease Sale on September 5 and 6, 2018 (the “BLM Acquisition”). The acquired leasehold acreage includes approximately 2,800 gross and net acres in the Stateline asset area on the Texas/New Mexico border, 4,800 gross and net acres in the Antelope Ridge asset area, 400 gross and net acres in the Arrowhead asset area and 400 gross and net acres in the Twin Lakes asset area. The leases for all tracts covering the BLM Acquisition were issued in the fourth quarter of 2018.

At February 26, 2019, we were actively pursuing drilling permits on a number of these tracts, including the approximately 2,800 gross and net acres in the Stateline asset area and the approximately 1,200 gross and net acres in the western portion of the Antelope Ridge asset area. We expect to begin drilling operations on these Stateline and western Antelope Ridge properties as early as the fourth quarter of 2019 or the first quarter of 2020.

Midstream Highlights

On January 22, 2018, we announced a strategic relationship between a subsidiary of San Mateo and a subsidiary of Plains to gather and transport crude oil for upstream producers in and around the Rustler Breaks asset area in Eddy County, New Mexico. Subsidiaries of San Mateo and Plains have agreed to work together through a joint tariff arrangement and related transactions to offer third-party producers located within a joint development area of approximately 400,000 acres in Eddy County, New Mexico (the “Joint Development Area”) crude oil transportation services from the wellhead to Midland, Texas with access to other end markets, such as Cushing and the Gulf Coast.

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, in December 2018, San Mateo 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”) following a successful open season to gauge shipper interest in committed crude oil interstate transportation service on the Rustler Breaks Oil Pipeline System earlier in 2018.

In late March 2018, San Mateo completed the expansion of the Black River Processing Plant, adding an incremental designed inlet capacity of 200 MMcf of natural gas per day and bringing the total designed inlet capacity of the Black River Processing Plant to 260 MMcf of natural gas per day. The expanded Black River Processing Plant supports our exploration and development activities in the Delaware Basin, and with the expanded capacity, San Mateo can offer natural gas processing services to other producers as well.

In October 2018, a subsidiary of San Mateo entered into a long-term agreement with a 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 the Company, at December 31, 2018, 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 June 2018, a subsidiary of San Mateo entered into a long-term agreement with another 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.

2019 Recent Developments

On February 25, 2019, we announced the formation of San Mateo Midstream II, LLC (“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 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 million of the first $150 million of capital expenditures incurred by San Mateo II to

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develop facilities in the Stebbins area and the Stateline asset area. Five Point has also provided us the opportunity to earn deferred performance incentives of up to $150 million over the next five years as we execute our operational plans in and around the Stebbins area and the Stateline asset area, plus additional performance incentives for securing volumes from third-party customers.

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 and East Texas. During 2018, 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. We have also sought to balance the risk profile of our asset areas by exploring for and developing more conventional targets as well, although for the year ended December 31, 2018, essentially all of our efforts were focused on unconventional plays.

The following table presents certain summary data for each of our operating areas as of and for the year ended December 31, 2018.

	Gross Acreage	Net Acreage	Producing Wells Gross	Producing Wells Net	Total Identified Drilling Locations (1) Gross	Total Identified Drilling Locations (1) Net	Estimated Net Proved Reserves (2) MBOE (3)	Estimated Net Proved Reserves (2) % Developed	Avg. Daily Production (BOE/d) (3)
Southeast New Mexico/West Texas:									
Delaware Basin (4)	222,200	132,000	630	290.7	5,442	2,472.2	191,490	42.3	45,237
South Texas:									
Eagle Ford (5)	32,000	28,900	148	122.5	238	206.9	12,189	61.5	3,158
Northwest Louisiana/East Texas:									
Haynesville	19,600	12,000	227	20.4	395	100.2	10,919	46.5	3,417
Cotton Valley (6)	21,100	18,600	79	53.3	71	49.2	715	100.0	316
Area Total (7)	25,500	22,800	306	73.7	466	149.4	11,634	49.8	3,733
Total	279,700	183,700	1,084	486.9	6,146	2,828.5	215,313	43.8	52,128

(1) Identified and engineered drilling locations. These locations have been identified for potential future drilling and were not producing at December 31, 2018. 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 location represents a one-mile lateral. At December 31, 2018, these engineered drilling locations included only 301 gross (147.6 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 and Strawn formations, in the Delaware Basin, 17 gross (17.0 net) locations to which we have assigned proved undeveloped reserves in the Eagle Ford and 14 gross (4.9 net) locations to which we have assigned proved undeveloped reserves in the Haynesville.

(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, 2018.

(5) Includes one well producing small quantities 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.

(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 and East Texas. 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, 2018, 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, 2018, we also were the operator for approximately 94% of our Eagle Ford acreage and approximately 64% of our Haynesville acreage, including

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approximately 32% 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 an affiliate of Chesapeake Energy Corporation.
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.
As noted above in "—2018 Highlights—Operational Highlights," we increased our acreage position in the Delaware Basin during 2018, and as a result, at December 31, 2018, our total acreage position in Southeast New Mexico and West Texas was approximately 222,200 gross (132,000 net) acres, primarily in Loving County, Texas and Lea and Eddy Counties, New Mexico. These acreage totals included approximately 34,200 gross (17,500 net) acres in our Ranger asset area in Lea County, 60,100 gross (25,700 net) acres in our Arrowhead asset area in Eddy County, 45,300 gross (26,200 net) acres in our Rustler Breaks asset area in Eddy County, 20,500 gross (17,300 net) acres in our Antelope Ridge asset area in Lea County, 14,400 gross (10,700 net) acres in our Wolf and Jackson Trust asset areas in Loving County, 2,800 gross (2,800 net) acres in our recently acquired Stateline asset area in Eddy County and 44,300 gross (31,300 net) acres in our Twin Lakes asset area in Lea County at December 31, 2018. 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, 2018, our acreage position in the Delaware Basin was approximately 54% held by existing production. Excluding the Twin Lakes asset area, where we have drilled only one vertical operated well and two horizontal operated wells, and the acreage acquired in 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, 2018.
During the year ended December 31, 2018, we continued the delineation and development of our Delaware Basin acreage. We completed and began producing oil and natural gas from 141 gross (73.8 net) wells in the Delaware Basin, including 82 gross (66.8 net) operated wells and 59 gross (7.0 net) non-operated wells, throughout our various asset areas. At December 31, 2018, we had tested a number of different producing horizons at various locations across

our acreage position, including the Brushy Canyon, 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 2018. Our average daily oil equivalent production from the Delaware Basin increased approximately 54% 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, as compared to 29,463 BOE per day (76% of total oil equivalent production), including 18,023 Bbl of oil per day (84% of total oil production) and 68.6

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MMcf of natural gas per day (66% of total natural gas production), in 2017. Our average daily oil equivalent production from the Delaware Basin also grew approximately 41% from 34,859 BOE per day in the fourth quarter of 2017 to 49,309 BOE per day in the fourth quarter of 2018.

At December 31, 2018, approximately 89% of our estimated total proved oil and natural gas reserves, or 191.5 million BOE, was attributable to the Delaware Basin, including approximately 114.8 million Bbl of oil and 460.0 Bcf of natural gas, a 48% increase, as compared to 129.0 million BOE for the year ended December 31, 2017. Our Delaware Basin proved reserves at December 31, 2018 comprised approximately 93% of our proved oil reserves and 83% of our proved natural gas reserves, as compared to approximately 89% of our proved oil reserves and 78% of our proved natural gas reserves at December 31, 2017.

At December 31, 2018, we had identified 5,442 gross (2,472.2 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 3,451 gross (2,278.0 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 assumes 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 observed on 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, 2018 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 these properties may be developed on 80- to 160-acre well spacing and that multiple intervals may be prospective at any one surface location. Although we believe that denser well spacing may be possible, at December 31, 2018, 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, 2018, these potential future drilling locations included 301 gross (147.6 net) locations in the Delaware Basin, primarily in the Wolfcamp and Bone Spring plays, but also in the Brushy Canyon, Avalon and Strawn formations, to which we have assigned proved undeveloped reserves.

At December 31, 2018, we were operating six drilling rigs in the Delaware Basin, and we expect to operate these six rigs in the Delaware Basin throughout 2019, including two rigs in each of the Rustler Breaks and Antelope Ridge asset areas, one rig in the Wolf/Jackson Trust asset areas and one rig in the Ranger/Arrowhead and Twin Lakes asset areas. 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 12 months. The other three rigs are on short-term contracts with remaining obligations of six 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. We are also planning to participate in non-operated wells in the Delaware Basin as these opportunities arise in 2019.

Rustler Breaks Asset Area - Eddy County, New Mexico

We operated two to three drilling rigs in our Rustler Breaks asset area during most of 2018. We completed and turned to sales 83 gross (41.8 net) horizontal wells and two gross (1.5 net) vertical wells in the Rustler Breaks asset area in 2018, including 46 gross (38.0 net) operated and 39 gross (5.3 net) non-operated wells. Most of these wells were completed in the Wolfcamp A-XY or Wolfcamp B-Blair intervals.

One of the key achievements of our drilling and completions program in our Rustler Breaks asset area in 2018 was our first operated two-mile horizontal well—the David Edelstein State Com 12&11-24S-27E RB #203H (Edelstein #203H) well, a Wolfcamp A-XY completion. The Edelstein #203H well tested 2,378 BOE per day (77% oil) during a 24-hour IP test in the third quarter of 2018.

We were pleased in 2018 with the success of our wells drilled in the northwestern portion of our acreage position. For example, the Miss Sue 12-23S-27E RB #201H (Miss Sue #201H) and the Michael Collins 11-23S-27E RB #201H (Michael Collins #201H) wells tested 1,706 BOE per day (76% oil) and 2,125 BOE per day (78% oil), respectively, during 24-hour IP tests. The Joe Coleman 13-23S-27E RB #201H and #203H (Joe Coleman #201H and #203H) wells

tested 1,702 BOE per day (80% oil) and 1,831 BOE per day (73% oil), respectively, during 24-hour IP tests. In seven months of production, the Joe Coleman #201H and #203H wells have produced approximately 210,000 BOE (69% oil) and 190,000 BOE (70% oil), respectively.
In addition, the Garrett Fed Com #122H (Garrett #122H) well, a Second Bone Spring completion in the Rustler Breaks asset area, flowed 2,411 BOE per day (84% oil) during a 24-hour IP test. We expect to further delineate the Second Bone Spring formation moving to the northwest in our Rustler Breaks asset area using two-mile laterals beginning in the latter part of 2019 or early 2020.

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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 2018. We operated one drilling rig in our Wolf and Jackson Trust asset areas during 2018, and we completed and turned to sales 11 gross (8.0 net) operated horizontal wells in these asset areas. Most of these wells were completed in the Wolfcamp A-XY interval.

In the fourth quarter of 2018, we completed and placed on production the Wolf 80-TTT-B33 WF #206H and #208H (Wolf #206H and #208H) wells. These wells tested 2,509 BOE per day (41% oil) and 2,514 BOE per day (39% oil), respectively, during 24-hour IP tests. We attribute these well results to the selection of an improved landing target identified through the use of 3-D seismic data, the longer lateral lengths drilled and completed (5,600 and 6,200 feet, respectively) and an improved stimulation design.

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

We operated one drilling rig in our Arrowhead, Ranger and Twin Lakes asset areas during 2018. We completed and turned to sales 13 gross (7.9 net) horizontal wells in the Arrowhead and Ranger asset areas in 2018, including 10 gross (7.5 net) operated and three gross (0.4 net) non-operated wells. Most of these wells were completed in the Second Bone Spring and Third Bone Spring intervals.

The SST 6 State #123H and #124H wells, our first two Second Bone Spring wells drilled on the SST leasehold north of the Stebbins acreage in the Arrowhead asset area, tested 2,056 BOE per day (85% oil) and 1,845 BOE per day (86% oil), respectively, during 24-hour IP tests. The SST 6 State #123H well has produced approximately 240,000 BOE (70% oil) in its first eight months of production, and the SST 6 State #124H well has produced approximately 180,000 BOE (73% oil) in its first eight months of production.

In addition, we believe recent Wolfcamp wells drilled by Matador and other operators demonstrate the prospectivity of the Wolfcamp formation moving north in the Delaware Basin. We achieved positive Wolfcamp results in the Ranger asset area with the recent completion of the Verna Rae Federal Com #204H (Verna Rae #204H) well about three miles southwest of our Mallon wells. The Verna Rae #204H well flowed 1,586 BOE per day (90% oil) during a 24-hour IP test.

Antelope Ridge Asset Area - Lea County, New Mexico

We operated one to two drilling rigs in our Antelope Ridge asset area during 2018. We completed and turned to sales 29 gross (13.2 net) horizontal wells in this asset area in 2018, including 14 gross (12.3 net) operated and 15 gross (0.9 net) non-operated wells. As we began to delineate the Antelope Ridge asset area during 2018, we tested six different intervals, completing wells in the Brushy Canyon, First, Second and Third Bone Spring, Wolfcamp A-XY and Wolfcamp A-Lower.

In particular, we were pleased with our delineation of the Wolfcamp A-Lower in the Antelope Ridge asset area. The Strong 14-24S-33E AR #214H (Strong #214H) well, our second Wolfcamp A-Lower test in the Antelope Ridge asset area, flowed 3,670 BOE per day (77% oil) during a 24-hour IP test. The Strong #214H well was a successful follow-up to our initial Wolfcamp A-Lower well in the Antelope Ridge asset area, the Leo Thorsness 13-24S-33E AR #211H (Leo Thorsness #211H) well, which flowed 2,906 BOE per day (72% oil) during a 24-hour IP test. The Strong #214H well has produced approximately 225,000 BOE (75% oil) in its first four months of production, and the Leo Thorsness #211H well has produced approximately 325,000 BOE (72% oil) in its first 11 months of production.

We also achieved several strong results in the Bone Spring in the Antelope Ridge asset area. The Irvin Wall State Com #131H (Irvin Wall #131H) well, our initial Third Bone Spring test in the Antelope Ridge asset area, flowed 2,343 BOE per day (81% oil) during a 24-hour IP test. The Irvin Wall #131H well has produced approximately 150,000 BOE (85% oil) in its first seven months of production. In addition, the Bill Alexander State Com #111H (Bill Alexander #111H) well, our second First Bone Spring test in the Antelope Ridge asset area, flowed 1,808 BOE per day (79% oil) during a 24-hour IP test. The Bill Alexander #111H well was a strong follow-up test of the First Bone Spring formation north of our initial First Bone Spring completion in the Antelope Ridge asset area, the Marlan Downey 9-23S-35E AR #111H well, which tested 1,491 BOE per day (82% oil) during a 24-hour IP test. The Bill Alexander #111H well has produced approximately 175,000 BOE (80% oil) in its first seven months of production.

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Twin Lakes Asset Area - Lea County, New Mexico

In 2018, we performed our first test of the Wolfcamp D formation in the western portion of our Twin Lakes asset area in northern Lea County, New Mexico. This well, the Northeast Kemnitz #233H well, tested approximately 675 BOE per day (84% oil) on electric submersible pump during a 24-hour IP test. This well has exhibited a shallow production decline similar to the D. Culbertson 26-15S-36E TL State #234H (D. Culbertson #234H) well, which was drilled and completed in 2017 and tested approximately 600 BOE per day (82% oil) during a 24-hour IP test. At December 31, 2018, we estimated an ultimate recovery of approximately 400,000 BOE from the D. Culbertson #234H well. Oil production from the D. Culbertson #234H well has been essentially flat, averaging approximately 110 Bbl of oil per day over the past 18 months, resulting in upward revisions to its estimated ultimate recovery.

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% net revenue interest (“NRI”) as compared to approximately 75% NRI on most fee leases today. As a result, we will retain an additional 17% of the net production from each well drilled and completed on these properties. 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. The BLM has formally issued these leases, and we have begun actively pursuing drilling permits on these tracts. We expect to begin drilling operations on these properties in early 2020.

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, 2018, our properties included approximately 32,000 gross (28,900 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, 2018, and essentially all of our Eagle Ford acreage was either held by production at December 31, 2018 or not burdened by lease expirations before 2020.

In early October 2018, we added one operated drilling rig to conduct a short-term drilling program in South Texas to drill up to 10 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 to hold by production almost all of our remaining undeveloped Eagle Ford acreage. This rig operated in South Texas throughout the fourth quarter of 2018 and into early 2019. When drilling operations were finalized on the ninth well in early February 2019, this rig was released and was not moved to the Delaware Basin as we had previously anticipated. 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, are expected to be completed and turned to sales late in the first quarter or early in the second quarter of 2019.

Our average daily oil equivalent production from the Eagle Ford shale decreased 28% 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, as compared to 4,413 BOE per day, including 3,475 Bbl of oil per day and 5.6 MMcf of natural gas per day, during 2017. For the year ended December 31, 2018, 6% of our total daily oil equivalent production was attributable to the Eagle Ford shale, as compared to 11% for the year ended December 31, 2017.

At December 31, 2018, approximately 6% of our estimated total proved oil and natural gas reserves, or 12.2 million BOE, was attributable to the Eagle Ford shale, including approximately 8.5 million Bbl of oil and 21.9 Bcf of natural gas. Our Eagle Ford total proved reserves comprised approximately 7% of our proved oil reserves and 4% of our proved natural gas reserves at December 31, 2018, as compared to approximately 11% of our proved oil reserves and 5% of our proved natural gas reserves at December 31, 2017.

At December 31, 2018, we had identified 238 gross (206.9 net) engineered locations for potential future drilling on our Eagle Ford acreage. Each drilling location 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 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, 2018, these 238 gross (206.9 net) identified drilling locations included 17 gross (17.0 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, 2018, 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 recent activity from other operators in these formations around our South Texas acreage position has demonstrated the potential prospectivity of these intervals.

Northwest Louisiana and East Texas — 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 and East Texas, including principally Bossier, Caddo, DeSoto and Red River Parishes in Louisiana and Harrison, Rusk, Panola and Shelby Counties in Texas. 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 and East Texas during 2018, although we did participate in the drilling and completion of eight gross (0.2 net) non-operated Haynesville shale wells that were turned to sales in 2018. We do not plan to drill any operated Haynesville shale or Cotton Valley wells in 2019.

At December 31, 2018, we held approximately 25,500 gross (22,800 net) acres in Northwest Louisiana and East Texas, including 19,600 gross (12,000 net) acres in the Haynesville shale play and 21,100 gross (18,600 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 and East Texas, 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 32% of the 13,200 gross (6,400 net) acres that we consider to be in the core area of the Haynesville shale play.

For the year ended December 31, 2018, approximately 7% of our average daily oil equivalent production, or 3,733 BOE per day, including 12 Bbl of oil per day and 22.3 MMcf of natural gas per day, was attributable to our leasehold interests in Northwest Louisiana and East Texas. Natural gas production from these properties comprised approximately 17% of our daily natural gas production during 2018, as compared to approximately 29% of our daily natural gas production during 2017. During the year ended December 31, 2017, approximately 13% of our average daily oil equivalent production, or 5,060 BOE per day, including 12 Bbl of oil per day and 30.4 MMcf of natural gas per day, was attributable to our properties in Northwest Louisiana and East Texas.

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. For the year ended December 31, 2017, approximately 27% of our daily natural gas production, or 28.3 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 2%, or 2.1 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties. At December 31, 2018, approximately 5% of our estimated total proved reserves, or 10.9 million BOE, was attributable to the Haynesville shale with another 0.3% of our proved reserves, or 0.7 million BOE, attributable to the Cotton Valley and shallower formations underlying this acreage.

At December 31, 2018, we had identified 395 gross (100.2 net) engineered locations for potential future drilling in the Haynesville shale play and 71 gross (49.2 net) engineered locations for potential future drilling in the Cotton Valley formation. Each drilling location 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

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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 395 gross (100.2 net) locations identified for future drilling on our Haynesville acreage, 321 gross (47.2 net) locations have been identified within the 13,200 gross (6,400 net) acres that we believe are located in the core area of the Haynesville shale play. As we explore and develop our Northwest Louisiana and East Texas acreage further, we believe it is possible that we may identify additional locations for future drilling. At December 31, 2018, these potential future drilling locations included 14 gross (4.9 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, a strategic joint venture with a subsidiary of Five Point. The midstream assets that were contributed to San Mateo 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. We earned $14.7 million in performance incentives effective January 31, 2018, which was paid by Five Point in the first quarter of 2018. Through January 31, 2019, we had earned an additional $14.7 million in performance incentives that we expect to be paid by Five Point in the first quarter of 2019 and may earn up to an additional $44.1 million in performance incentives over the next three years. We continue to operate the Delaware Midstream Assets and retain operational control of San Mateo. The Company and Five Point own 51% and 49% of San Mateo, respectively. San Mateo continues to provide firm capacity service to us at market rates, while also being a midstream service provider to other customers in and around our Wolf and Rustler Breaks asset areas.

In February 2019, we announced an expansion of our midstream business with the formation of San Mateo II. For additional information regarding this strategic joint venture, see “—2019 Recent Developments.”

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 2017, 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 60 MMcf of natural gas per day. As noted above in “—2018 Highlights—Midstream Highlights,” San Mateo completed this expansion of the Black River Processing Plant in late March 2018, bringing the total designed inlet capacity of the Black River Processing Plant to 260 MMcf of natural gas per day. 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.

As noted above in “—2018 Highlights—Midstream Highlights,” 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, 2018, 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 an 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 in February 2017.

At December 31, 2018, San Mateo's natural gas gathering systems included natural gas gathering pipelines and related compression and treating systems. During the year ended December 31, 2018, San Mateo gathered approximately 46.1 Bcf of natural gas, as compared to 32.1 Bcf of natural gas gathered during the year ended December 31, 2017. In addition, during the year ended December 31, 2018, San Mateo processed approximately 32.3 Bcf of natural gas, as compared to 18.4 Bcf of natural gas processed during the year ended December 31, 2017.

Crude Oil Gathering and Transportation Assets

As noted above in "—2018 Highlights—Midstream Highlights," subsidiaries of San Mateo and 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.

Also, as noted above in "—2018 Highlights—Midstream Highlights," San Mateo completed its expanded Wolf Oil Pipeline System in May 2018 and placed into service 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, 2018, we estimated we had on pipe almost all of our oil production from the Wolf and Rustler Breaks asset areas, which comprised approximately 70% of our Delaware Basin oil production in the fourth quarter of 2018. With the San Mateo Oil Pipeline Systems in service, we expect to improve our oil price realizations in the Wolf and Rustler Breaks asset areas through the elimination of higher priced trucking services.

At December 31, 2018, 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, 2018, the San Mateo Oil Pipeline Systems had throughput of approximately 2.0 million Bbl of oil, as compared to 0.5 million Bbl of oil throughput during the year ended December 31, 2017.

Produced Water Gathering and Disposal Assets

During 2018, San Mateo placed into service three commercial salt water disposal wells in the Rustler Breaks asset area and placed into service one additional commercial salt water disposal well there in February 2019, bringing San Mateo's commercial salt water disposal well count in the Rustler Breaks asset area to six at February 26, 2019. In addition to its six commercial salt water disposal wells and associated facilities in the Rustler Breaks asset area, at February 26, 2019, 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. At February 26, 2019, San Mateo had a designed disposal capacity of approximately 250,000 Bbl of salt water per day.

As noted above in "—2018 Highlights—Midstream Highlights," 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.

During the year ended December 31, 2018, San Mateo gathered approximately 44.0 million Bbl of salt water, as compared to 20.0 million Bbl of salt water gathered during the year ended December 31, 2017. In addition, during the year ended December 31, 2018, San Mateo disposed of approximately 47.5 million Bbl of salt water, as compared to 23.6 million Bbl of salt water disposed of during the year ended December 31, 2017.

South Texas / Northwest Louisiana and East Texas

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 and East Texas, we have midstream assets that gather and treat natural gas from most of our operated leases and from third parties and five non-commercial salt water disposal wells that dispose of our salt water. Our midstream assets in South Texas and Northwest Louisiana and East Texas are not part of San Mateo.

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Operating Summary

The following table sets forth certain unaudited production and operating data for the years ended December 31, 2018, 2017 and 2016.

	Year Ended December 31,		
	2018	2017	2016
Unaudited Production Data:			
Net Production Volumes:			
Oil (MBbl)	11,141	7,851	5,096
Natural gas (Bcf)	47.3	38.2	30.5
Total oil equivalent (MBOE) (1)	19,026	14,212	10,180
Average daily production (BOE/d) (1)	52,128	38,936	27,813
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$57.04	$49.28	$41.19
Oil, with realized derivatives (per Bbl)	$57.38	$48.81	$42.34
Natural gas, without realized derivatives (per Mcf)	$3.49	$3.72	$2.66
Natural gas, with realized derivatives (per Mcf)	$3.46	$3.70	$2.78
Operating Expenses (per BOE):			
Production taxes, transportation and processing	$4.00	$4.10	$4.23
Lease operating	$4.89	$4.74	$5.52
Plant and other midstream services operating	$1.29	$0.92	$0.53
Depletion, depreciation and amortization	$13.94	$12.49	$11.99
General and administrative	$3.64	$4.65	$5.41

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(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, 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/East Texas		
	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	—	12	30,523
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	$67.40	$—	$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.

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(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/East Texas		
	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.

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The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2016 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/East Texas		
	Delaware Basin	Eagle Ford [(1)]	Haynesville	Cotton Valley [(2)]	Total
Annual Net Production Volumes					
Oil (MBbl)	3,805	1,286	—	5	5,096
Natural gas (Bcf)	12.2	3.1	14.3	0.9	30.5
Total oil equivalent (MBOE) [(3)]	5,834	1,813	2,385	148	10,180
Percentage of total annual net production	57.3 %	17.8 %	23.4 %	1.5 %	100.0 %
Average Net Daily Production Volumes					
Oil (Bbl/d)	10,395	3,517	—	12	13,924
Natural gas (MMcf/d)	33.3	8.6	39.1	2.3	83.3
Total oil equivalent (BOE/d)	15,941	4,952	6,517	403	27,813
Average Sales Prices [(4)]					
Oil (per Bbl)	$ 41.76	$39.49	$—	$38.78	$41.19
Natural gas (per Mcf)	$ 3.15	$3.11	$2.17	$2.27	$2.66
Total oil equivalent (per BOE)	$ 33.81	$33.46	$13.04	$14.39	$28.60
Production Costs [(5)]					
Lease operating, transportation and processing (per BOE)	$ 7.32	$12.74	$4.73	$17.07	$7.82

(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 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 where we have significantly reduced our operated activity since late 2014 and early 2015. 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.

Our total oil equivalent production of approximately 14.2 million BOE for the year ended December 31, 2017 increased 40% from our total oil equivalent production of approximately 10.2 million BOE for the year ended December 31, 2016. 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, 2017 was 38,936 BOE per day, as compared to 27,813 BOE per day for the year ended December 31, 2016. Our average daily oil production for the year ended December 31, 2017 was 21,510 Bbl of oil per day, an increase of 54% from 13,924 Bbl of oil per day for the year ended December 31, 2016. Our average daily natural gas production for the year ended December 31, 2017 was 104.6 MMcf of natural gas per day, an increase of 25% from 83.3 MMcf of natural gas per day for the year ended December 31, 2016.

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Producing Wells

The following table sets forth information relating to producing wells at December 31, 2018. Wells are classified as oil wells or natural gas wells according to their predominant production stream. We had an approximate average working interest of 77% in all wells that we operated at December 31, 2018. For wells where we are not the operator, our working interests range from less than 1% to as much as just over 50%, and average approximately 11%. 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)]	519	241.0	111	49.7	630	290.7
South Texas:						
Eagle Ford [(2)]	144	118.5	4	4.0	148	122.5
Northwest Louisiana/East Texas:						
Haynesville	—	—	227	20.4	227	20.4
Cotton Valley [(3)]	2	2.0	77	51.3	79	53.3
Area Total	2	2.0	304	71.7	306	73.7
Total	665	361.5	419	125.4	1,084	486.9

(1) Includes 224 gross (58.6 net) vertical wells that were acquired in multiple transactions.

(2) 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.

(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, 2018, 2017 and 2016. 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 the SEC's 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.

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	At December 31, [1]		
	2018	2017	2016
Estimated Proved Reserves Data: [2]			
Estimated proved reserves:			
Oil (MBbl)	123,401	86,743	56,977
Natural Gas (Bcf)	551.5	396.2	292.6
Total (MBOE) [3]	215,313	152,771	105,752
Estimated proved developed reserves:			
Oil (MBbl)	53,223	36,966	22,604
Natural Gas (Bcf)	246.2	190.1	126.8
Total (MBOE) [3]	94,261	68,651	43,731
Percent developed	43.8 %	44.9 %	41.4 %
Estimated proved undeveloped reserves:			
Oil (MBbl)	70,178	49,777	34,373
Natural Gas (Bcf)	305.2	206.1	165.9
Total (MBOE) [3]	121,052	84,120	62,021
Standardized Measure [4] (in millions)	$2,250.6	$1,258.6	$575.0
PV-10 [5] (in millions)	$2,579.3	$1,333.4	$581.5

(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, 2018 were $62.04 per Bbl for oil and $3.10 per MMBtu for natural gas, for the 12 months ended December 31, 2017 were $47.79 per Bbl for oil and $2.98 per MMBtu for natural gas, and for the 12 months ended December 31, 2016 were $39.25 per Bbl for oil and $2.48 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, 2018, 2017 and 2016 may be reconciled to our Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2018, 2017 and 2016 were, in millions, $328.7, $74.8 and $6.5, respectively.

Our estimated total proved oil and natural gas reserves increased 41% from 152.8 million BOE at December 31, 2017 to 215.3 million BOE at December 31, 2018. We added 69.6 million BOE in proved oil and natural gas reserves through extensions and discoveries throughout 2018, approximately 3.7 times our 2018 annual production of 19.0 million BOE. Our proved oil reserves grew 42% from approximately 86.7 million Bbl at December 31, 2017 to approximately 123.4 million Bbl at December 31, 2018. Our proved natural gas reserves increased 39% from 396.2

Bcf at December 31, 2017 to 551.5 Bcf at December 31, 2018. This increase in proved oil and natural gas reserves was primarily a result of our delineation and development operations in the Delaware Basin during 2018. We realized approximately 11.3 million BOE in net upward revisions to our proved reserves during 2018 primarily as a result of upward technical revisions resulting from better-than-projected well performance from certain wells, as compared to December 31, 2017. Our proved reserves to production ratio at December 31, 2018 was 11.3, an increase of 4% from 10.8 at December 31, 2017.

Over the past two years, our estimated total proved oil and natural gas reserves more than doubled, increasing 104% from 105.8 million BOE at December 31, 2016 to 215.3 million Bbl at December 31, 2018. Our proved oil reserves grew 117% from 57.0 million Bbl at December 31, 2016 to 123.4 million Bbl at December 31, 2018. Our proved developed oil reserves increased 135% from 22.6 million Bbl at December 31, 2016 to 53.2 million Bbl at December 31, 2018.

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The Standardized Measure of our total proved oil and natural gas reserves increased 79% from $1.26 billion at December 31, 2017 to $2.25 billion at December 31, 2018. The PV-10 of our total proved oil and natural gas reserves increased 93% from $1.33 billion at December 31, 2017 to $2.58 billion at December 31, 2018. The increases in our Standardized Measure and PV-10 are primarily a result of our delineation and development drilling activities in the Delaware Basin during 2018 and higher weighted average oil and natural gas prices used to estimate proved reserves at December 31, 2018, as compared to December 31, 2017. The unweighted arithmetic averages of first-day-of-the-month oil and natural gas prices used to estimate proved reserves at December 31, 2018 were $62.04 per Bbl and $3.10 per MMBtu, an increase of 30% and 4%, respectively, as compared to average oil and natural gas prices of $47.79 per Bbl and $2.98 per MMBtu used to estimate proved reserves at December 31, 2017. Our total proved reserves were made up of 57% oil and 43% natural gas at December 31, 2018, as compared to 57% oil and 43% natural gas at December 31, 2017. 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 37% from 68.7 million BOE at December 31, 2017 to 94.3 million BOE at December 31, 2018 due primarily to our delineation and development operations in the Delaware Basin. Our proved developed oil reserves increased 44% from 37.0 million Bbl at December 31, 2017 to 53.2 million Bbl at December 31, 2018. Our proved developed natural gas reserves increased 30% from 190.1 Bcf at December 31, 2017 to 246.2 Bcf at December 31, 2018.

The following table summarizes changes in our estimated proved developed reserves at December 31, 2018.

	Proved Developed Reserves (MBOE) [(1)]
As of December 31, 2017	68,651
Extensions and discoveries	14,666
Purchases of minerals-in-place	596
Revisions of prior estimates	3,091
Production	(19,026)
Conversion of proved undeveloped to proved developed	26,283
As of December 31, 2018	94,261

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(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 44% from 84.1 million BOE at December 31, 2017 to 121.1 million BOE at December 31, 2018. Our proved undeveloped oil and natural gas reserves increased from 49.8 million Bbl and 206.1 Bcf, respectively, at December 31, 2017 to 70.2 million Bbl and 305.2 Bcf, respectively, at December 31, 2018, primarily as a result of our delineation and development operations in the Delaware Basin.

At December 31, 2018, 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, 2018 within five years of booking these reserves.

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The following table summarizes changes in our estimated proved undeveloped reserves at December 31, 2018.

	Proved Undeveloped Reserves (MBOE) [(1)]
As of December 31, 2017	84,120
Extensions and discoveries	54,980
Purchases of minerals-in-place	—
Revisions of prior estimates	8,235
Conversion of proved undeveloped to proved developed	(26,283)
As of December 31, 2018	121,052

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

The following table sets forth, since 2015, proved undeveloped reserves converted to proved developed reserves during each year and the investments associated with these conversions (dollars in thousands).

	Proved Undeveloped Reserves Converted to Proved Developed Reserves			Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves
	Oil (MBbl)	Natural Gas (Bcf)	Total (MBOE) [(1)]	
2015	2,854	23.4	6,747	104,989
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
Total	32,868	143.2	56,721	$ 768,258

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(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, 2018.

	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	114,823	460.0	191,490	$ 2,056.7	$ 2,357.1
South Texas:					
Eagle Ford [(5)]	8,537	21.9	12,189	160.9	184.4
Northwest Louisiana/East Texas:					
Haynesville	—	65.5	10,919	31.0	35.5
Cotton Valley [(6)]	41	4.1	715	2.0	2.3
Area Total	41	69.6	11,634	33.0	37.8
Total	123,401	551.5	215,313	$ 2,250.6	$ 2,579.3

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(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, 2018 may be reconciled to our Standardized Measure of discounted future net cash flows at such date by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2018 were approximately $328.7 million.

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

(5) 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.

(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 41 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, 2018.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/West Texas:						
Delaware Basin	123,000	71,900	99,200	60,100	222,200	132,000
South Texas:						
Eagle Ford	29,900	26,800	2,100	2,100	32,000	28,900
Northwest Louisiana/East Texas (1):						
Haynesville	19,000	11,500	600	500	19,600	12,000
Cotton Valley	20,400	18,500	700	100	21,100	18,600
Area Total (2)	24,300	22,200	1,200	600	25,500	22,800
Total	177,200	120,900	102,500	62,800	279,700	183,700

(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 and East Texas.

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Undeveloped Acreage Expiration

The following table sets forth the approximate number of gross and net undeveloped acres at December 31, 2018 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 2024 and beyond totals 13,500 net acres, of which 8,800 net acres do not expire until 2028.

	Acres Expiring 2019		Acres Expiring 2020		Acres Expiring 2021		Acres Expiring 2022		Acres Expiring 2023	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/West Texas:										
Delaware Basin (1)	13,900	9,400	16,400	8,900	25,100	14,900	7,600	8,200	4,000	5,400
South Texas:										
Eagle Ford	100	100	1,600	1,500	400	400	—	—	—	—
Northwest Louisiana/East Texas:										
Haynesville	300	300	200	200	—	—	—	—	—	—
Cotton Valley	—	—	—	—	—	—	—	—	—	—
Area Total (2)	300	300	200	200	—	—	—	—	—	—
Total	14,300	9,800	18,200	10,600	25,500	15,300	7,600	8,200	4,000	5,400

(1) Approximately 49% 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 through our 2019 drilling activities or by paying an additional lease bonus, where applicable.

(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 and East Texas.

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, 2018, 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, 2018, 2017 and 2016.

	Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	118	54.7	72	43.7	44	23.5
Dry	—	—	—	—	—	—
Exploration Wells						
Productive	35	20.8	33	22.3	28	15.6
Dry	—	—	—	—	—	—
Total Wells						

Productive	153	75.5	105	66.0	72	39.1
Dry	—	—	—	—	—	—

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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 a portion of our heavier liquids move up and down in direct correlation with the oil market as it reacts to supply and demand factors. The prices of the remaining lighter liquids 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, 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."

For the years ended December 31, 2018, 2017 and 2016, we had four, four and three significant purchasers, respectively, that accounted for approximately 60%, 60% and 48%, 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 assure 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. 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.

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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. We have been conducting field operations since 2004 while 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 statutes or 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 or restriction on 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.

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 26, 2019, 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 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 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 transportation services subject to FERC jurisdiction by any entity, to direct FERC to facilitate transparency in the market for the sale or transportation of natural gas in interstate commerce and to significantly increase 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

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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 — Recently Enacted Tax Legislation 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

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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, citing uncertainty caused by litigation surrounding the validity of this rule, in 2018 the EPA and the Corps announced a two-year stay of the application of the rule. Federal district court decisions have preserved the stay in Texas, New Mexico and Louisiana, and such jurisdictions remain subject to pre-2015 WOTUS regulations. As noted, litigation surrounding this rule is ongoing. On December 11, 2018, the EPA and the Corps released a proposal to revise the 2015 Clean Water Rule so as to narrow the regulatory definition of WOTUS, with a 60-day comment period to follow.

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

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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, on October 28, 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

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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. We do not expect these developments to have a material adverse effect on our business, financial condition, results of operations and cash flows.

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. Some states and localities have placed additional regulatory burdens upon hydraulic fracturing activities and, in some areas, severely restricted or prohibited those activities. In February 2019, a bill was introduced in the New Mexico Senate to place a moratorium on hydraulic fracturing that, if enacted, would last through June 1, 2023. 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, will result in additional expense and delay in our operations. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves. 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."

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.

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.

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A significant portion 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.

Office Lease

Our corporate headquarters are located at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. See Note 13 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, 2018, we had 264 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, particularly 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.

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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, and our Code of Ethics and Business Conduct for Officers, Directors and Employees, 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 2018, the average price of oil was $64.89 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 $3.07 per MMBtu, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. During 2018, oil prices began the year at $60.42 per Bbl and reached a high of $76.41 per Bbl in early October. Throughout the fourth quarter of 2018, however, oil prices declined more than 40% from the high in early October to a low of $42.53 per Bbl in late December. Natural gas prices began 2018 at $2.95 per MMBtu and reached a high of $4.84 per MMBtu in mid-November before declining to $2.94 per MMBtu in late December. 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 caused us to recognize full-cost ceiling impairments in the first two quarters of 2016, and should prices decline 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;
- 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, Middle East, South America and Russia;
- 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 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, to cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities or to 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

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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 or oil and natural gas producing assets or acreage, 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 future 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 before they can be drilled. The budgeted costs of planning, drilling, completing and operating wells are often 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. For example, risks that we face while drilling and completing horizontal wells include, but are not limited to, the following:

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- 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.

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 Unforeseen Interruptions for Which We May Not Be Adequately Insured.

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

- natural disasters;
- adverse weather conditions;
- 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.

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

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Northwest Louisiana and East Texas. 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 the year ended 2018 was attributable to our properties in the Delaware Basin. In 2016, 2017 and 2018, the vast majority of our capital expenditures were allocated to the Delaware Basin. We expect that substantially all of our capital expenditures in 2019 will continue to be in the Delaware Basin, with the exception of amounts incurred in 2019 to conclude our South Texas drilling program and 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 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.

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.

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.

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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 26, 2019, the maximum facility amount under the Credit Agreement was $1.5 billion, the borrowing base was $850.0 million and our elected borrowing commitment was $500.0 million. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, maximum facility amount and elected borrowing commitment. At February 26, 2019, we had available borrowing capacity of approximately $406.3 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 26, 2019, the facility amount under the San Mateo Credit Facility was $250.0 million, and San Mateo had available borrowing capacity of approximately $13.8 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 guaranteed by San Mateo’s subsidiaries and secured by substantially all of San Mateo’s assets, including real property. The San Mateo Credit Facility contains covenants restricting San Mateo’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 fund acquisitions, develop our properties 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 26, 2019, our borrowing base was $850.0 million, our elected borrowing commitment was $500.0 million and we had $80.0 million in outstanding borrowings under, and approximately $13.7 million in outstanding letters of credit issued pursuant to, the Credit Agreement. As of February 26, 2019, 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 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’s Consolidated Total Leverage Ratio (as defined in the San Mateo Credit Facility). If San Mateo 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’s Consolidated Total Leverage Ratio. If San Mateo has outstanding borrowings under the San Mateo Credit Facility and interest rates increase, so will San Mateo’s interest costs, which may have a material adverse effect on San Mateo’s results of operations 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 any decline in the prices of oil or natural gas 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 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 to maintain an interest coverage ratio, which is defined as a rolling four quarter EBITDA calculation divided by San Mateo’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’s EBITDA and interest expense, and therefore San Mateo’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

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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 26, 2019, 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, 2018, 2017 and 2016, we had four, four and three significant purchasers, respectively, that collectively accounted for approximately 60%, 60% and 48%, 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.

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

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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 Drill 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 in which our competitors have been active. As a result of this activity, we may have difficulty expanding 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.

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.

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

San Mateo owns, and we operate, the Black River Processing Plant. There are significant risks associated with the operation of cryogenic natural gas processing plants. 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 the Rustler Breaks asset area. 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

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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 flow could be adversely affected.

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 Supplies, 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 supplies. 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 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, 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.

Gathering, Processing and Transportation Services Are Subject to Complex Federal, State and Other Laws That Could Adversely Affect the Cost, Manner or Feasibility of Conducting Our Business.

The operations of our midstream business, including San Mateo, and the operations of the third parties on whom we rely for gathering, processing and transportation services, are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. Substantial costs may be incurred in order to comply with existing laws and regulations. If existing laws and regulations governing such services are revised or reinterpreted, or if new laws and regulations become applicable to operations, these changes may affect the costs that we pay for such services or the results of our midstream business, including San Mateo. Similarly, a failure to comply with such laws and regulations by us or the parties on whom we rely could have a material adverse effect on our business, financial condition, results of operations and cash flows. See "Business — Regulation."

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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 56% of Our Total Proved Reserves at December 31, 2018 Consisted of Undeveloped and Developed Non-Producing Reserves, and Those Reserves May Not Ultimately Be Developed or Produced.

At December 31, 2018, approximately 56% of our total proved reserves were undeveloped and approximately 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.

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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, 2018, we had leasehold interests in approximately 49,300 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 2024. 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 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.

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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 will 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.

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.

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 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 2019. 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.

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 will 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.

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, 2018, our long-term contractual obligations under agreements with minimum volume commitments totaled approximately $641.2 million over the terms of the agreements. In addition, in connection with the formation of San Mateo II, we entered into agreements with minimum volume commitments that totaled approximately $363.8 million. 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 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, South Texas, Southeast New Mexico and West 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.

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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 26, 2019, we had approximately 50% and 15% of our estimated remaining 2019 oil and natural gas production, respectively, hedged. We currently have no hedges in place for NGLs, limited oil basis hedges in place for 2020 and otherwise no hedges in place beyond 2019 for oil or natural gas.

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 that we receive for our oil and natural gas production sometimes reflect a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the benchmark prices and the prices we receive is called a differential. Increases in the differential between the benchmark prices for oil and natural gas and the wellhead prices we receive could adversely affect our business, financial condition, results of operations and cash flows. For example, we sell much of our natural gas produced from the Delaware Basin at the Waha Hub. The price differential between the Waha Hub index and the Henry Hub index increased significantly through 2018 from approximately $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 at the end of the year. The natural gas price differential had narrowed to between $1.00 and $2.00 per MMBtu at the beginning of 2019, although it is possible that the differential could widen again at certain times during 2019. Similarly, we sell much of our oil produced from the Delaware Basin at the Midland (Texas) Hub. 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, also increased significantly through 2018 from essentially no difference in the first quarter of 2018 to as much as $16.00 per Bbl in late September. The oil price differential had narrowed to about $5.00 per Bbl at the beginning of 2019, although it is possible that the differential could widen again at certain times during 2019. We have no derivative contracts in place to mitigate our exposure to these oil and natural gas price differentials during 2019 and have limited oil basis hedges in place for 2020.

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 and 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. In addition to expenditures required in order for us to comply with such laws and regulations, these expenditures could also include payments for:

- personal injuries;

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

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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 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 facilities are located, or the owners of properties adjacent to or in close proximity to those properties, 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. 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 ability to develop and produce our reserves.

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. 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.

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Recently Enacted Tax Legislation 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 did not pass, legislation to amend the SDWA, to remove the SDWA's exemption granted to most hydraulic fracturing operations (other than operations using fluids containing diesel) and to require reporting and disclosure of chemicals used by oil and natural gas companies in the hydraulic fracturing process. Also at the federal level, 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 in March 2015. 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. 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 February 2019, a bill was introduced in the New Mexico Senate to place a moratorium on hydraulic fracturing that, if enacted, would last through June 1, 2023.

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 oil and natural gas waste 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 linkage 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 linkage between oil and natural gas activity and induced seismicity, some state regulatory agencies, including in Texas, have modified their regulations or guidance to mitigate potential causes of induced seismicity.

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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 or 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 June 2017, the Trump administration announced its intention for the United States to withdraw from the Paris Agreement. Pursuant to the terms of the Paris Agreement, the earliest date the United States can withdraw is November 2020. 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 September 2018 proposed targeted improvements to the rule, including amendments to the rule's fugitive emissions monitoring requirements, which are expected to "significantly reduce" the rule's regulatory burden. 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. 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 with certainty, 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. If regions reclassified as non-attainment areas under the lower ozone standard begin implementing new, more stringent regulations, those regulations could also apply to our or our customers’ operations. Generally, it will take the states several years to develop compliance plans for their non-attainment areas. The EPA’s final rule has been judicially challenged by both industry and other interested parties, and the outcome of this litigation may also impact implementation and revisions to the rule. 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 which scaled back the waste-prevention requirements of the 2016 rule. Environmental groups 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 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.

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A Change in the Jurisdictional Characterization of Some of Our Assets by FERC or a Change in Policy by It 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 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 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. As of February 26, 2019, the shippers on the Rustler Breaks Oil Pipeline System have agreed not to challenge, or to cause others to challenge or assist others in challenging, our tariff rates in effect during the terms of their respective agreements; however, other current or future shippers may still challenge our tariff rates.

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 October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new

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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. During the last quarter of 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.

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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 not experienced any material losses due to cyber incidents, 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.

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 2018, our stock price fluctuated between a high of $35.22 and a low of $13.97. 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;
- 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;
- 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.

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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.

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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 26, 2019, 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 13 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 lawsuits encountered in the ordinary course of our business. While the ultimate outcome and impact to us cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on our financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures.

Not applicable.

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PART II

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 26, 2019, we had 116,388,317 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, 2018.

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)	2,962,249	$ 23.48	991,281
Equity compensation plans not approved by security holders	—	—	—
Total	2,962,249	$ 23.48	991,281

(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.

(2) The Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan was adopted by our Board of Directors in April 2015 and approved by our shareholders on June 10, 2015. For a description of our Amended and Restated 2012 Long-Term Incentive Plan, see Note 8 to the consolidated financial statements in this Annual Report.

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Share Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock from December 31, 2013 through December 31, 2018, 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

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Repurchase of Equity by the Company or Affiliates

During the quarter ended December 31, 2018, 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, 2018 to October 31, 2018	11,777	$ 33.39	—	—
November 1, 2018 to November 30, 2018	216	25.79	—	—
December 1, 2018 to December 31, 2018	106	15.49	—	—
Total	12,099	$ 33.10	—	—

(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.

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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, 2018 and selected consolidated balance sheet and cash flow data at December 31, 2018, 2017, 2016, 2015 and 2014. 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,				
	2018	2017	2016	2015	2014
(In thousands, except per share data)					
Statement of operations data:					
Revenues					
Oil and natural gas revenues	$800,700	$528,684	$291,156	$278,340	$367,712
Third-party midstream services revenues	21,920	10,198	5,218	1,864	1,213
Sales of purchased natural gas	7,071	—	—	—	—
Lease bonus - mineral acreage	2,489	—	—	—	—
Realized gain (loss) on derivatives	2,334	(4,321)	9,286	77,094	5,022
Unrealized gain (loss) on derivatives	65,085	9,715	(41,238)	(39,265)	58,302
Total revenues	899,599	544,276	264,422	318,033	432,249
Expenses					
Production taxes, transportation and processing	76,138	58,275	43,046	35,650	33,172
Lease operating	92,966	67,313	56,202	54,704	49,945
Plant and other midstream services operating	24,609	13,039	5,389	3,489	1,408
Purchased natural gas	6,635	—	—	—	—
Depletion, depreciation and amortization	265,142	177,502	122,048	178,847	134,737
Accretion of asset retirement obligations	1,530	1,290	1,182	734	504
Full-cost ceiling impairment	—	—	158,633	801,166	—
General and administrative	69,308	66,016	55,089	50,105	32,152
Total expenses	536,328	383,435	441,589	1,124,695	251,918
Operating income (loss)	363,271	160,841	(177,167)	(806,662)	180,331
Other income (expense)					
Net (loss) gain on asset sales and inventory impairment	(196)	23	107,277	908	—
Interest expense	(41,327)	(34,565)	(28,199)	(21,754)	(5,334)
Prepayment premium on extinguishment of debt	(31,226)	—	—	—	—
Other income (expense)	1,551	3,551	(4)	616	132
Total other (expense) income	(71,198)	(30,991)	79,074	(20,230)	(5,202)
Net income (loss)	299,764	138,007	(97,057)	(679,524)	110,754
Net (income) loss attributable to non-controlling interest in subsidiaries	(25,557)	(12,140)	(364)	(261)	17
Net income (loss) attributable to Matador Resources Company shareholders	$274,207	$125,867	$(97,421)	$(679,785)	$110,771
Earnings (loss) per common share					
Basic	$2.41	$1.23	$(1.07)	$(8.34)	$1.58
Diluted	$2.41	$1.23	$(1.07)	$(8.34)	$1.56

	At December 31,				
	2018	2017	2016	2015	2014
(In thousands)					
Balance sheet data:					
Cash and cash equivalents	$64,545	$96,505	$212,884	$16,732	$8,407

Restricted cash	$19,439	$5,977	$1,258	$44,357	$609
Net property and equipment	$3,122,864	$1,881,456	$1,184,525	$1,012,406	$1,322,072
Total assets	$3,455,518	$2,145,690	$1,464,665	$1,140,861	$1,434,490
Current liabilities	$330,022	$282,606	$169,505	$136,830	$142,036
Long-term liabilities	$1,345,839	$605,538	$603,715	$515,072	$425,913
Total Matador Resources Company shareholders' equity	$1,688,880	$1,156,556	$690,125	$488,003	$866,408

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	Year Ended December 31,				
	2018	2017	2016	2015	2014
(In thousands)					
Other financial data:					
Net cash provided by operating activities	$608,523	$299,125	$134,086	$208,535	$251,481
Net cash used in investing activities	$(1,515,253)	$(819,284)	$(448,739)	$(381,406)	$(569,922)
Oil and natural gas properties capital expenditures	$(1,357,802)	$(699,445)	$(379,067)	$(432,715)	$(560,849)
Expenditures for midstream and other property and equipment	$(165,784)	$(120,816)	$(74,845)	$(64,499)	$(9,152)
Net cash provided by financing activities	$888,232	$408,499	$467,706	$224,944	$321,170
Adjusted EBITDA attributable to Matador Resources Company shareholders [(1)]	$553,223	$336,063	$157,892	$223,138	$262,943

(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 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 cash flows from 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.

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The following table presents our 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.

	Year Ended December 31,				
	2018	2017	2016	2015	2014
(In thousands)					
Unaudited Adjusted EBITDA Reconciliation to Net Income (Loss):					
Net income (loss) attributable to Matador Resources Company shareholders	$274,207	$125,867	$(97,421)	$(679,785)	$110,771
Net income (loss) attributable to non-controlling interest in subsidiaries	25,557	12,140	364	261	(17)
Net income (loss)	299,764	138,007	(97,057)	(679,524)	110,754
Interest expense	41,327	34,565	28,199	21,754	5,334
Total income tax (benefit) provision	(7,691)	(8,157)	(1,036)	(147,368)	64,375
Depletion, depreciation and amortization	265,142	177,502	122,048	178,847	134,737
Accretion of asset retirement obligations	1,530	1,290	1,182	734	504
Full-cost ceiling impairment	—	—	158,633	801,166	—
Unrealized (gain) loss on derivatives	(65,085)	(9,715)	41,238	39,265	(58,302)
Stock-based compensation expense	17,200	16,654	12,362	9,450	5,524
Net loss (gain) on asset sales and inventory impairment	196	(23)	(107,277)	(908)	—
Prepayment premium on extinguishment of debt	31,226	—	—	—	—
Consolidated Adjusted EBITDA	583,609	350,123	158,292	223,416	262,926
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(30,386)	(14,060)	(400)	(278)	17
Adjusted EBITDA attributable to Matador Resources Company shareholders	$553,223	$336,063	$157,892	$223,138	$262,943

	Year Ended December 31,				
	2018	2017	2016	2015	2014
(In thousands)					
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:					
Net cash provided by operating activities	$608,523	$299,125	$134,086	$208,535	$251,481
Net change in operating assets and liabilities	(64,429)	25,058	(1,809)	(8,980)	5,978
Interest expense, net of non-cash portion	39,970	34,097	27,051	20,902	5,334
Current income tax (benefit) provision	(455)	(8,157)	(1,036)	2,959	133
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(30,386)	(14,060)	(400)	(278)	17
Adjusted EBITDA attributable to Matador Resources Company shareholders	$553,223	$336,063	$157,892	$223,138	$262,943

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 borrowing base 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.”

Overview

We are an independent energy company founded in July 2003 and 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 and East Texas. 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.

2018 Operational Highlights

During the year ended December 31, 2018, we completed and began producing oil and natural gas from 82 gross (66.8 net) operated and 59 gross (7.0 net) non-operated wells in the Delaware Basin and from one gross (1.0 net) operated and three gross (0.5 net) non-operated Eagle Ford shale wells. We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana and East Texas during 2018, although we did participate in the drilling and completion of eight gross (0.2 net) non-operated Haynesville shale wells that began producing in 2018.

During 2018, 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 began 2018 operating six drilling rigs in the Delaware Basin and continued to do so through December 31, 2018. In early October 2018, we added a seventh operated drilling rig to our drilling program on a short-term contract in South Texas to drill up to 10 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 to hold by production almost all of our remaining undeveloped Eagle Ford acreage. This rig operated in South Texas throughout the fourth quarter of 2018 and into early 2019. When drilling operations were finalized on the ninth well in early February 2019, this rig was released and was not moved to the Delaware Basin as we had previously anticipated. 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, are expected to be completed and turned to sales late in the first quarter or early in the second quarter of 2019.

The vast majority of our 2018 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. Our remaining capital expenditures were primarily directed to the beginning of our short-term drilling and completion program in South Texas and to our participation in several non-operated wells drilled and completed in the Eagle Ford and Haynesville shales throughout 2018.

In September 2018, we announced the BLM Acquisition, pursuant to which we acquired 8,400 gross and net leasehold acres in Lea and Eddy Counties, New Mexico for approximately $387 million, or a weighted average cost of approximately $46,000 per net acre. In addition to the BLM Acquisition, we also acquired 21,400 net leasehold and mineral acres in the Delaware Basin during 2018, and as a result, at December 31, 2018, we held approximately 222,200 gross (132,000 net) acres in Southeast New Mexico and West Texas, primarily in the Delaware Basin, in Lea and Eddy Counties, New Mexico and Loving County, Texas.

Our average daily oil equivalent production for the year ended December 31, 2018 was 52,128 BOE per day, including 30,524 Bbl of oil per day and 129.6 MMcf of natural gas per day, an increase of 34% as compared to 38,936 BOE per day, including 21,510 Bbl of oil per day and 104.6 MMcf of natural gas per day, for the year ended December 31, 2017. Our average daily oil production in 2018 of 30,524 Bbl of oil per day increased 42%, as compared to an average daily oil production of 21,510 Bbl of oil per day in 2017. This increase in oil production was primarily a result of our ongoing delineation and development drilling activities in the Delaware Basin. Our average daily natural gas production of 129.6 MMcf per day for the year ended December 31, 2018 increased 24% from 104.6 MMcf per day for the year ended December 31, 2017. This increase in natural gas production was primarily attributable to increased natural gas production associated with our ongoing delineation and development drilling activities in the Delaware Basin. Oil production comprised 59% 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, 2018, as compared to 55% for the year ended December 31, 2017.

For the year ended December 31, 2018, our oil and natural gas revenues were $800.7 million, an increase of 51% from oil and natural gas revenues of $528.7 million for the year ended December 31, 2017. Our oil revenues and natural gas revenues increased 64% and 16% to approximately $635.6 million and $165.1 million, respectively, as compared to $386.9 million and $141.8 million, respectively, for the year ended December 31, 2017. The increase in oil and natural gas revenues resulted from (i) the increases in oil and natural gas production for the year ended December 31, 2018 as noted above and (ii) higher weighted average realized oil prices of $57.04 per Bbl in 2018, as compared to $49.28 per Bbl in 2017, offset by lower weighted average realized natural gas prices of $3.49 per Mcf in 2018, as compared to $3.72 per Mcf in 2017.

We reported net income attributable to Matador Resources Company shareholders of approximately $274.2 million, or $2.41 per diluted common share, on a GAAP basis for the year ended December 31, 2018, as compared to net income of $125.9 million, or $1.23 per diluted common share, for the year ended December 31, 2017. Adjusted EBITDA for the year ended

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December 31, 2018 was $553.2 million, as compared to Adjusted EBITDA of $336.1 million reported for the year ended December 31, 2017. 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, 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. At December 31, 2017, our estimated total proved oil and natural gas reserves were 152.8 million BOE, including 86.7 million Bbl of oil and 396.2 Bcf of natural gas, with a Standardized Measure of $1.26 billion and a PV-10 of $1.33 billion. Our estimated total proved reserves of 215.3 million BOE at December 31, 2018 represented a 41% year-over-year increase, as compared to 152.8 million BOE at December 31, 2017. Our estimated proved oil reserves of 123.4 million Bbl at December 31, 2018 increased 42%, as compared to 86.7 million Bbl at December 31, 2017. Our proved oil and natural gas reserves in the Delaware Basin increased 48% to 191.5 million BOE at December 31, 2018, as compared to 129.0 million BOE at December 31, 2017, primarily as a result of our ongoing delineation and development operations in the Delaware Basin. At December 31, 2018, approximately 89% 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 48% to 114.8 million Bbl at December 31, 2018, as compared to 77.5 million Bbl at December 31, 2017. Proved oil reserves comprised 57% of our total proved reserves at December 31, 2018, as compared to 57% at December 31, 2017. 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

We made significant progress in our midstream operations during 2018, including, among other accomplishments, (i) the completion and successful startup of the expansion of the Black River Processing Plant to a designed inlet capacity of 260 MMcf of natural gas per day, (ii) the completion of an NGL pipeline connection at the Black River Processing Plant to the NGL pipeline owned by EPIC Y-Grade Pipeline LP, (iii) the ongoing buildout of oil, natural gas and water pipeline systems in both the Rustler Breaks and Wolf asset areas, (iv) the entrance into a strategic relationship with Plains to gather and transport crude oil in the Rustler Breaks asset area, (v) placing into service crude oil gathering and transportation systems in the Wolf and Rustler Breaks asset areas, (vi) entering into long-term agreements with significant producers in Eddy County, New Mexico relating to the gathering and disposal of one such producer’s salt water and the gathering and processing of another such producer’s natural gas production and (vii) the drilling and completion of additional commercial salt water disposal wells and the construction of associated commercial facilities in the Rustler Breaks asset area, significantly increasing San Mateo’s salt water disposal capacity.

2019 Capital Expenditure Budget

We expect that development of our Delaware Basin assets will be the primary focus of our operations and capital expenditures in 2019. We plan to operate six contracted drilling rigs drilling primarily oil and natural gas wells in the Delaware Basin throughout most of 2019. Our 2019 estimated capital expenditure budget consists of $640 to $680 million for drilling, completing and equipping wells (“D/C/E capital expenditures”) and $55 to $75 million for midstream capital expenditures, which primarily reflects our proportionate share of San Mateo and San Mateo II’s estimated combined 2019 capital expenditures of $180 to $220 million and also accounts for portions of the $50 million capital carry that Five Point is expected to provide to us in conjunction with the formation of San Mateo II. Substantially all of our 2019 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 incurred in 2019 to conclude our South Texas drilling program and 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 2019 Delaware Basin drilling program is expected to focus on the continued development of the Rustler Breaks and Wolf asset areas and the further delineation and development of the Antelope Ridge, Jackson Trust, Ranger/Arrowhead and Twin Lakes asset areas as well as the federal leasehold acreage in the western portion of the Antelope Ridge asset area acquired in the BLM Acquisition.

As noted above, we were operating a seventh operated drilling rig at the beginning of 2019 to conduct the short-term drilling program in South Texas, primarily in the Eagle Ford shale. When we concluded this short-term program in February 2019, we released this drilling rig and did not move this rig to the Delaware Basin as we had previously anticipated. To further narrow any potential difference between our 2019 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 well as to consider monetizing other

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assets, such as certain mineral, royalty and non-core 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 2019. 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 2019 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 2019.

At December 31, 2018, we had $64.5 million in cash (excluding restricted cash) and $457.0 million in undrawn borrowing capacity under our Credit Agreement (after giving effect to outstanding letters of credit). As a result, we expect to fund our capital expenditures for 2019 through a combination of cash on hand, operating cash flows, performance incentives in connection with the formation of San Mateo that were earned in the first quarter of 2019, borrowings under our Credit Agreement (assuming availability under our borrowing base) and borrowings under the San Mateo Credit Facility. In addition, in 2019, we expect Five Point to provide a portion of the $50 million capital carry in connection with the formation of San Mateo II. We may also consider funding a portion of our 2019 capital expenditures through borrowings under additional credit arrangements, the sale or joint venture of midstream assets or oil and natural gas producing assets or leasehold interests, particularly in our non-core asset areas, the sale or joint venture of oil and natural gas mineral interests, as well as 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 of our midstream activities, other opportunities that may become available to us and our ability to obtain capital.

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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,		
	2018	2017	2016
Operating Data:			
Revenues (in thousands): (1)			
Oil	$635,554	$386,865	$209,908
Natural gas	165,146	141,819	81,248
Total oil and natural gas revenues	800,700	528,684	291,156
Third-party midstream services revenues	21,920	10,198	5,218
Sales of purchased natural gas	7,071	—	—
Lease bonus - mineral acreage	2,489	—	—
Realized gain (loss) on derivatives	2,334	(4,321)	9,286
Unrealized gain (loss) on derivatives	65,085	9,715	(41,238)
Total revenues	$899,599	$544,276	$264,422
Net Production Volumes: (1)			
Oil (MBbl)	11,141	7,851	5,096
Natural gas (Bcf)	47.3	38.2	30.5
Total oil equivalent (MBOE) (2)	19,026	14,212	10,180
Average daily production (BOE/d) (2)	52,128	38,936	27,813
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$57.04	$49.28	$41.19
Oil, with realized derivatives (per Bbl)	$57.38	$48.81	$42.34
Natural gas, without realized derivatives (per Mcf)	$3.49	$3.72	$2.66
Natural gas, with realized derivatives (per Mcf)	$3.46	$3.70	$2.78

(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, 2018 as Compared to Year Ended December 31, 2017

Oil and natural gas revenues. Our oil and natural gas revenues increased $272.0 million, or 51%, to $800.7 million for the year ended December 31, 2018, as compared to $528.7 million for the year ended December 31, 2017. Our oil revenues increased $248.7 million, or 64%, to $635.6 million for the year ended December 31, 2018, as compared to $386.9 million for the year ended December 31, 2017. The increase in oil revenues resulted from (i) the 42% increase in our oil production to 11.1 million Bbl of oil for the year ended December 31, 2018, or about 30,524 Bbl of oil per day, as compared to 7.9 million Bbl of oil, or about 21,510 Bbl of oil per day, for the year ended December 31, 2017, and (ii) a higher weighted average oil price realized for the year ended December 31, 2018 of $57.04 per Bbl, as compared to $49.28 per Bbl realized for the year ended December 31, 2017. This increased oil production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin. Our natural gas revenues increased by $23.3 million, or 16%, to $165.1 million for the year ended December 31, 2018, as compared to $141.8 million for the year ended December 31, 2017. The increase in natural gas revenues resulted from the 24% increase in our natural gas production to 47.3 Bcf for the year ended December 31, 2018, as compared to 38.2 Bcf for the year ended December 31, 2017, but was partially offset by a slightly lower weighted average natural gas price realized for the year ended December 31, 2018 of $3.49 per Mcf, as compared to $3.72 per Mcf realized for the year ended December 31, 2017. The increase in natural gas production was primarily attributable to our ongoing

delineation and development drilling activities in the Delaware Basin.
Third-party midstream services revenues. Our third-party midstream services revenues increased $11.7 million, or 115%, to $21.9 million for the year ended December 31, 2018, as compared to $10.2 million for the year ended December 31, 2017. Third-party midstream services revenues are only those revenues from midstream operations related to third parties, including working interest owners in our operated wells. This increase was primarily attributable to the significant increase in third-party salt water gathering and disposal revenues to approximately $10.5 million during the year ended December 31, 2018, as compared to approximately $2.1 million for the year ended December 31, 2017, resulting from an increase in salt water

gathering and disposal at our facilities in the Rustler Breaks and Wolf asset areas in 2018. The remaining increase in our third-party midstream services revenues was primarily attributable to an increase in natural gas gathering and processing revenues to approximately $10.7 million for the year ended December 31, 2018, as compared to $7.9 million for the year ended December 31, 2017, resulting from an increase in natural gas processing at the Black River Processing Plant. An expansion of the Black River Processing Plant from a designed capacity of 60 MMcf per day to 260 MMcf per day was completed and placed into service in early 2018.

Sales of purchased natural gas. Our sales of purchased natural gas were $7.1 million for the year ended December 31, 2018. We had no sales of purchased natural gas for the year ended December 31, 2017. Sales of purchased natural gas primarily reflect those natural gas purchase transactions that we may periodically enter into with third parties whereby we process the 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. 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 $2.5 million for the year ended December 31, 2018. We had no lease bonus revenues in 2017. 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 (loss) on derivatives. Our realized net gain on derivatives was $2.3 million for the year ended December 31, 2018, as compared to a net loss of approximately $4.3 million for the year ended December 31, 2017. 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 a net loss of $3.7 million and $0.6 million from our oil and natural gas derivative contracts, respectively, for the year ended December 31, 2017, resulting from oil and natural gas prices that were above the ceiling prices of certain of our oil and natural gas costless collar contracts. We realized an average gain on our oil derivatives of approximately $0.34 per Bbl of oil produced during the year ended December 31, 2018, as compared to an average loss of $0.47 per Bbl of oil produced during the year ended December 31, 2017. Our total oil volumes hedged for the year ended December 31, 2018 represented 49% of our total oil production, as compared to 59% of our total oil production for the year ended December 31, 2017. We realized an average loss on our natural gas and NGL derivatives of approximately $0.03 per Mcf produced during the year ended December 31, 2018, as compared to an average loss of approximately $0.02 per Mcf produced for the year ended December 31, 2017. Our total natural gas volumes hedged for the year ended December 31, 2018 represented 36% of our total natural gas production, as compared to 63% of our total natural gas production for the year ended December 31, 2017.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was approximately $65.1 million for the year ended December 31, 2018, as compared to an unrealized gain of $9.7 million for the year ended December 31, 2017. During the year ended December 31, 2018, the aggregate net fair value of our open oil and natural gas derivatives and oil basis swap 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. During the year ended December 31, 2017, the aggregate net fair value of our open oil and natural gas derivative contracts increased from a net liability of approximately $25.0 million to a net liability of approximately $15.2 million, resulting in an unrealized gain on derivatives of approximately $9.7 million for the year ended December 31, 2017.

Year Ended December 31, 2017 as Compared to Year Ended December 31, 2016

Oil and natural gas revenues. Our oil and natural gas revenues increased $237.5 million, or 82%, to $528.7 million for the year ended December 31, 2017, as compared to $291.2 million for the year ended December 31, 2016. Our oil revenues increased $177.0 million, or 84%, to $386.9 million for the year ended December 31, 2017, as compared to $209.9 million for the year ended December 31, 2016. The increase in oil revenues resulted from (i) a higher weighted average oil price realized for the year ended December 31, 2017 of $49.28 per Bbl, as compared to $41.19 per Bbl realized for the year ended December 31, 2016, and (ii) the 54% increase in our oil production to 7.9 million Bbl of oil for the year ended December 31, 2017, or about 21,510 Bbl of oil per day, as compared to 5.1 million Bbl of oil, or about 13,924 Bbl of oil per day, for the year ended December 31, 2016. This increased oil production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin, but also to production from the five operated wells we completed and turned to sales in the Eagle Ford shale late in the second quarter and early in the third quarter of 2017. Our natural gas revenues increased by $60.6 million, or 75%, to $141.8 million for the year ended December 31, 2017, as compared to $81.2 million for the year ended December 31, 2016. The increase in natural gas revenues resulted from (i) a higher weighted average natural gas price realized for the year ended December 31, 2017 of $3.72 per Mcf, as compared to $2.66 per Mcf realized for the year ended December 31, 2016, and (ii) the 25% increase in our natural gas production to 38.2 Bcf for the year ended December 31, 2017, as compared to 30.5 Bcf for the year ended December 31, 2016. The increase in natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin.

Third-party midstream services revenues. Our third-party midstream services revenues increased $5.0 million, or 95%, to $10.2 million for the year ended December 31, 2017, as compared to $5.2 million for the year ended December 31, 2016. 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 a significant increase in natural gas gathering and processing revenues to approximately $7.9 million for the year ended December 31, 2017, as compared to $3.6 million for the year ended December 31, 2016, due to (i) the Black River Processing Plant being placed into service in the second half of 2016 and operating for the full year in 2017 and (ii) increased natural gas production in our Rustler Breaks and Wolf asset areas. The remaining increase in our third-party midstream services revenues was primarily attributable to the increase in third-party salt water disposal revenues to approximately $2.1 million during the year ended December 31, 2017, as compared to approximately $1.6 million for the year ended December 31, 2016, primarily due to an increase in salt water gathering and disposal at our facilities in the Rustler Breaks and Wolf asset areas in 2017.

Realized (loss) gain on derivatives. Our realized net loss on derivatives was $4.3 million for the year ended December 31, 2017, as compared to a net gain of approximately $9.3 million for the year ended December 31, 2016. We realized net losses of $3.7 million and $0.6 million from our oil and natural gas costless collar contracts, respectively, for the year ended December 31, 2017, resulting from oil and natural gas prices that were above the ceiling prices of certain of our oil and natural gas costless collar contracts. We realized net gains of $5.9 million and $3.4 million from our oil and natural gas derivative contracts, respectively, for the year ended December 31, 2016, 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 an average loss on our oil derivatives of approximately $0.47 per Bbl produced during the year ended December 31, 2017, as compared to an average gain of $1.15 per Bbl produced during the year ended December 31, 2016. Our total oil volumes hedged for the year ended December 31, 2017 represented 59% of our total oil production, as compared to 50% of our total oil production for the year ended December 31, 2016. We realized an average loss on our natural gas and NGL derivatives of approximately $0.02 per Mcf produced during the year ended December 31, 2017, as compared to an average gain of approximately $0.12 per Mcf produced for the year ended December 31, 2016. Our total natural gas volumes hedged for the year ended December 31, 2017 represented 63% of our total natural gas production, as compared to 44% of our total natural gas production for the year ended December 31, 2016.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was approximately $9.7 million for the year ended December 31, 2017, as compared to an unrealized loss of $41.2 million for the year ended December 31, 2016. During the year ended December 31, 2017, the aggregate net fair value of our open oil and natural gas derivatives contracts increased from a net liability of approximately $25.0 million to a net liability of approximately $15.2 million, resulting in an unrealized gain on derivatives of approximately $9.7 million for the year ended December 31, 2017. During the year ended December 31, 2016, the aggregate net fair value of our open oil and natural gas derivative contracts decreased from a net asset of approximately $16.3 million to a net liability of approximately $25.0 million, resulting in an unrealized loss on derivatives of approximately $41.2 million for the year ended December 31, 2016.

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Expenses

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

	Year Ended December 31,		
	2018	2017	2016
(In thousands, except expenses per BOE)			
Expenses:			
Production taxes, transportation and processing	$76,138	$58,275	$43,046
Lease operating	92,966	67,313	56,202
Plant and other midstream services operating	24,609	13,039	5,389
Purchased natural gas	6,635	—	—
Depletion, depreciation and amortization	265,142	177,502	122,048
Accretion of asset retirement obligations	1,530	1,290	1,182
Full-cost ceiling impairment	—	—	158,633
General and administrative	69,308	66,016	55,089
Total expenses	536,328	383,435	441,589
Operating income (loss)	363,271	160,841	(177,167)
Other income (expense):			
Net (loss) gain on asset sales and inventory impairment	(196)	23	107,277
Interest expense	(41,327)	(34,565)	(28,199)
Prepayment premium on extinguishment of debt	(31,226)	—	—
Other income (expense)	1,551	3,551	(4)
Total other (expense) income	(71,198)	(30,991)	79,074
Income (loss) before income taxes	292,073	129,850	(98,093)
Total income tax benefit	(7,691)	(8,157)	(1,036)
Net income attributable to non-controlling interest in subsidiaries	(25,557)	(12,140)	(364)
Net income (loss) attributable to Matador Resources Company shareholders	$274,207	$125,867	$(97,421)
Expenses per BOE:			
Production taxes, transportation and processing	$4.00	$4.10	$4.23
Lease operating	$4.89	$4.74	$5.52
Plant and other midstream services operating	$1.29	$0.92	$0.53
Depletion, depreciation and amortization	$13.94	$12.49	$11.99
General and administrative	$3.64	$4.65	$5.41

Year Ended December 31, 2018 as Compared to Year Ended December 31, 2017

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased by approximately $17.9 million, or 31%, to $76.1 million for the year ended December 31, 2018, as compared to $58.3 million for the year ended December 31, 2017. The increase in production taxes, transportation and processing expenses on an absolute basis was primarily attributable to the $25.0 million increase in our production taxes to $58.0 million for the year ended December 31, 2018, as compared to $33.0 million for the year ended December 31, 2017, resulting from the $272.0 million increase in oil and natural gas revenues for the year ended December 31, 2018, as compared to the year ended December 31, 2017. The increased production taxes were partially offset by a decrease in transportation and processing expenses. Transportation and processing expenses decreased to $18.2 million for the year ended December 31, 2018, as compared to $25.3 million for the year ended December 31, 2017. On a unit-of-production basis, our production taxes, transportation and processing expenses decreased to $4.00 per BOE for the year ended December 31, 2018, as compared to $4.10 per BOE for the year ended December 31, 2017, which was attributable to the 34% increase in total oil equivalent production between the respective periods.

Lease operating expenses. Our lease operating expenses increased by $25.7 million, or 38%, to $93.0 million for the year ended December 31, 2018, as compared to $67.3 million for the year ended December 31, 2017. Our lease operating expenses on a unit-of-production basis increased 3% to $4.89 per BOE for the year ended December 31, 2018, as compared to $4.74 per BOE for the year ended December 31, 2017. The increase in lease operating expenses for the year ended December 31, 2018 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, 2018, as compared to the year ended December 31, 2017, resulting from our increased delineation and development drilling activities in the Delaware Basin.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased by $11.6 million, or 89%, to $24.6 million for the year ended December 31, 2018, as compared to $13.0 million for the year ended

December 31, 2017. This increase was primarily attributable to (i) increased expenses associated with our expanded commercial salt water disposal operations of $13.1 million for the year ended December 31, 2018, as compared to $6.8 million for the year ended December 31, 2017, (ii) increased expenses associated with the Black River Processing Plant, where a significant expansion was completed and placed into service in the first quarter of 2018, of $7.6 million for the year ended December 31, 2018, as compared to $4.6 million for the year ended December 31, 2017, and (iii) increased expenses associated with our expanded pipeline operations in the Wolf and Rustler Breaks asset areas of $3.5 million for the year ended December 31, 2018, as compared to $1.3 million for the year ended December 31, 2017.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $87.6 million, or 49%, to $265.1 million for the year ended December 31, 2018, as compared to $177.5 million for the year ended December 31, 2017. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased 12% to $13.94 per BOE for the year ended December 31, 2018, as compared to $12.49 per BOE for the year ended December 31, 2017. The increase in both our total and unit-of-production depletion, depreciation and amortization expenses was primarily attributable to (i) higher estimated future development costs associated with proved undeveloped oil and natural gas reserves at December 31, 2018, which was partially offset by the increase in our total proved oil and natural gas reserves between the respective periods, and (ii) increased depreciation expenses associated with our expanded midstream assets of approximately $10.5 million for the year ended December 31, 2018, as compared to $5.2 million for the year ended December 31, 2017.

General and administrative. Our general and administrative expenses increased $3.3 million, or 5%, to $69.3 million for the year ended December 31, 2018, as compared to $66.0 million for the year ended December 31, 2017. The increase in our general and administrative expenses was primarily attributable to increased payroll expenses of approximately $10.7 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 $6.8 million for the year ended December 31, 2018. Our general and administrative expenses decreased 22% on a unit-of-production basis to $3.64 per BOE for the year ended December 31, 2018, as compared to $4.65 per BOE for the year ended December 31, 2017, primarily attributable to the 34% increase in total oil equivalent production between the respective periods.

Interest expense. For the year ended December 31, 2018, we incurred total interest expense of approximately $50.2 million. We capitalized approximately $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. For the year ended December 31, 2017, we incurred total interest expense of approximately $41.9 million. We capitalized $7.3 million of our interest expense on certain qualifying projects for the year ended December 31, 2017 and expensed the remaining $34.6 million to operations. The increase in total interest expense for the year ended December 31, 2018, as compared to the year ended December 31, 2017, 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, as compared to $575.0 million at December 31, 2017.

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 $575.0 million aggregate principal amount of 2023 Notes.

Total income tax (benefit) provision. We recorded a total income tax benefit of $7.7 million for the year ended December 31, 2018. Total income tax expense for the year ended December 31, 2018 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to (i) the change of approximately $80.0 million in our federal valuation allowance for the year ended December 31, 2018, including the reversal of the valuation allowance, as we now believe we will be able to use the federal net operating losses prior to expiration, (ii) the partial reversal of a state valuation allowance of approximately $2.9 million on our state deferred tax assets for the year ended December 31, 2018, as we now believe we will be able to use the state net operating losses prior to expiration, and (iii) the impact of permanent differences between book and taxable income. Our deferred tax assets exceeded our deferred tax liabilities at December 31, 2017 due to the deferred tax amounts generated by the full-cost ceiling impairment charges recorded in prior periods. We established a valuation allowance against the deferred tax assets beginning in the third quarter of 2015, and we retained a full valuation allowance at December 31, 2017, due to uncertainties regarding the future realization of our deferred tax assets. The current tax benefit of $8.2 million for the year ended December 31, 2017 was primarily the result of the Tax Cuts and Jobs Act, under which corporate alternative minimum taxes were repealed.

Year Ended December 31, 2017 as Compared to Year Ended December 31, 2016

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased by approximately $15.2 million, or 35%, to $58.3 million for the year ended December 31, 2017, as compared to $43.0 million for the year ended December 31, 2016. The increase in production taxes, transportation and processing expenses on an absolute basis was primarily attributable to the $16.4 million increase in our production taxes to $33.0 million for the year ended December 31, 2017, as compared to $16.6 million for the year ended December 31, 2016, primarily due to the $237.5 million increase in oil and natural gas revenues for the year ended December 31, 2017, as compared to the year ended December 31, 2016. In addition, the production tax rates in New Mexico are higher than production tax rates in Texas. As more of our oil and natural gas production becomes attributable to New Mexico, we expect our production tax expenses to increase. The increased production taxes were partially offset by a decrease in transportation and processing expenses. Transportation and processing expenses decreased to $25.3 million for the year ended December 31, 2017, as compared to transportation and processing expenses of $26.5 million for the year ended December 31, 2016. This decrease of $1.2 million was primarily due to the start-up in late August 2016 of the Black River Processing Plant, which processes most of the natural gas produced in our Rustler Breaks asset area in Eddy County, New Mexico, and which was operational for the full year in 2017. On a unit-of-production basis, our production taxes, transportation and processing expenses decreased to $4.10 per BOE for the year ended December 31, 2017, as compared to $4.23 per BOE for the year ended December 31, 2016, due not only to the decreased transportation and processing charges attributable to the start-up of the Black River Processing Plant, but also to the 40% increase in total oil equivalent production during the year ended December 31, 2017, as compared to the year ended December 31, 2016.

Lease operating expenses. Our lease operating expenses increased by $11.1 million, or 20%, to $67.3 million for the year ended December 31, 2017, as compared to $56.2 million for the year ended December 31, 2016. The increase in lease operating expenses on an absolute basis for the year ended December 31, 2017 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, 2017, as compared to the year ended December 31, 2016, resulting from our increased delineation and development drilling activities in the Delaware Basin. Our lease operating expenses on a unit-of-production basis decreased 14% to $4.74 per BOE for the year ended December 31, 2017, as compared to $5.52 per BOE for the year ended December 31, 2016. The decrease in lease operating expenses on a unit-of-production basis for the year ended December 31, 2017 was attributable to (i) increased efficiencies as more salt water was gathered by pipeline to San Mateo’s disposal facilities in the Delaware Basin, (ii) decreased workover expenses, (iii) decreased salt water disposal and chemical costs associated with our Eagle Ford operations and (iv) a 40% increase in total oil equivalent production in 2017, as compared to 2016.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased by $7.7 million, or 142%, to $13.0 million for the year ended December 31, 2017, as compared to $5.4 million for the year ended December 31, 2016. This increase was primarily attributable to (i) increased expenses associated with our expanded commercial salt water disposal operations of $6.8 million for the year ended December 31, 2017, as compared to $3.6 million for the year ended December 31, 2016, and (ii) increased expenses associated with the Black River Processing Plant, which began operating in August 2016, of $4.6 million for the year ended December 31, 2017, as compared to $0.7 million for the year ended December 31, 2016.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $55.5 million, or 45%, to $177.5 million for the year ended December 31, 2017, as compared to $122.0 million for the year ended December 31, 2016. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased 4% to $12.49 per BOE for the year ended December 31, 2017, as compared to $11.99 per BOE for the year ended December 31, 2016. The increase in both our total depletion, depreciation and amortization and unit-of-production depletion, depreciation and amortization expenses was primarily attributable to (i) increased depreciation expenses of approximately $5.2 million for the year ended December 31, 2017, as compared to $2.7 million for the year ended December 31, 2016, associated with our new midstream assets placed into service in 2017 and (ii) higher estimated future development costs associated with proved undeveloped oil and natural gas reserves at December 31, 2017, both of which were offset by the increase in our total proved oil and natural gas reserves between the respective periods.

Full-cost ceiling impairment. We recorded no impairment charge to the net capitalized costs of our oil and natural gas properties for the year ended December 31, 2017. We recorded an impairment charge of $158.6 million to the net capitalized costs of our oil and natural gas properties for the year ended December 31, 2016.

General and administrative. Our general and administrative expenses increased $10.9 million, or 20%, to $66.0 million for the year ended December 31, 2017, as compared to $55.1 million for the year ended December 31, 2016. The increase in our general and administrative expenses was primarily attributable to increased payroll expenses of approximately $10.4 million associated with additional employees joining the Company to support our increased land, geoscience, drilling, completion, production, midstream, accounting and administration functions as a result of the continued growth of the

Company and to the $4.3 million increase in non-cash stock-based compensation expense to $16.7 million for the year ended December 31, 2017, as compared to $12.4 million for the year ended December 31, 2016. The increase in our non-cash stock-based compensation was attributable to the increased expense related to the vesting of awards granted from 2013 through 2017 and the granting of new awards during 2017, as well as a change in the vesting schedule applicable to equity awards granted to our board of directors resulting in a $1.5 million one-time stock-based compensation expense. Our general and administrative expenses decreased 14% on a unit-of-production basis to $4.65 per BOE for the year ended December 31, 2017, as compared to $5.41 per BOE for the year ended December 31, 2016, primarily due to the 40% increase in total oil equivalent production between the respective periods.

Net gain on asset sales and inventory impairment. We recorded a net gain of $23,000 on asset sales and inventory impairment for the year ended December 31, 2017, as compared to a net gain of $107.3 million for the year ended December 31, 2016 related to the sale of our wholly-owned subsidiary that owned the Loving County Processing System. See Note 5 to the consolidated financial statements in this Annual Report for more information on this sale.

Interest expense. For the year ended December 31, 2017, we incurred total interest expense of approximately $41.9 million. We capitalized approximately $7.3 million of our interest expense on certain qualifying projects for the year ended December 31, 2017 and expensed the remaining $34.6 million to operations. For the year ended December 31, 2016, we incurred total interest expense of approximately $31.9 million. We capitalized $3.7 million of our interest expense on certain qualifying projects for the year ended December 31, 2016 and expensed the remaining $28.2 million to operations. The increase in total interest expense for the year ended December 31, 2017, as compared to the year ended December 31, 2016, was primarily attributable to an increase in our average debt outstanding. In December 2016, we issued an additional $175.0 million of 2023 Notes, increasing our total senior notes outstanding to $575.0 million from $400.0 million. As a result, we incurred interest on the entire $575.0 million in senior notes outstanding during the year ended December 31, 2017, as compared to the year ended December 31, 2016, when the $575.0 million of senior notes were outstanding for only a portion of December 2016.

Total income tax (benefit) provision. Our deferred tax assets exceeded our deferred tax liabilities at December 31, 2017 due to the deferred tax amounts generated by the full-cost ceiling impairment charges recorded in prior periods. We established a valuation allowance against the deferred tax assets beginning in the third quarter of 2015, and we retained a full valuation allowance at December 31, 2017 due to uncertainties regarding the future realization of our deferred tax assets. The current tax benefit of $8.2 million for the year ended December 31, 2017 was primarily the result of the Tax Cuts and Jobs Act, under which corporate alternative minimum taxes were repealed. As a result, corporate alternative minimum tax carryforwards will be refunded. The total income tax expense for the years ended December 31, 2017 and 2016 differed from amounts computed by applying the U.S. federal statutory tax rate to the pre-tax income or loss, respectively, due primarily to recording a valuation allowance against the net deferred tax asset position as a result of the full-cost ceiling impairments recorded for the years ended December 31, 2016 and 2015.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue to be during 2019 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 capital expenditure requirements through 2019 through a combination of cash on hand, operating cash flows, performance incentives in connection with the formation of San Mateo that were earned in the first quarter of 2019, borrowings under our Credit Agreement (assuming availability under our borrowing base) and borrowings under the San Mateo Credit Facility. In addition, in 2019, we expect Five Point to provide a portion of the $50 million capital carry in connection 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 or oil and natural gas producing assets or leasehold interests, particularly in our non-core asset areas, the sale or joint venture of oil and natural gas mineral interests, as well as 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, 2018, we had cash totaling approximately $64.5 million and restricted cash totaling approximately $19.4 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.

On May 17, 2018, we completed a public offering of 7,000,000 shares of our common stock, receiving net proceeds of approximately $226.4 million after deducting offering costs totaling approximately $0.2 million. The proceeds from this offering were used to acquire additional leasehold and mineral acres in the Delaware Basin, to fund certain midstream initiatives in the Delaware Basin and for general corporate purposes, including to fund a portion of our capital expenditures.

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Pending such uses, we used a portion of the proceeds from the offering to repay the $45.0 million in borrowings then outstanding under our Credit Agreement.

As of December 31, 2017, we had $575.0 million of outstanding 2023 Notes with a coupon rate of 6.875%. On August 21, 2018, we issued $750.0 million of Original 2026 Notes with a coupon rate of 5.875% in a private placement. The Original 2026 Notes were issued at par value, and we received net proceeds of approximately $740.0 million, after deducting the initial purchasers' discounts and estimated offering expenses. In conjunction with the offering of the Original 2026 Notes (the "2026 Notes Offering"), in August and September 2018, respectively, we completed a tender offer and redemption of all of the 2023 Notes (the "2023 Notes Tender Offer and Redemption"). We used a portion of the net proceeds from the 2026 Notes Offering to fund the 2023 Notes Tender Offer and Redemption.

In September 2018, we announced the BLM Acquisition, pursuant to which we acquired 8,400 gross and net leasehold acres in Lea and Eddy Counties, New Mexico for approximately $387 million, or a weighted average cost of approximately $46,000 per net acre. We financed the BLM Acquisition using cash on hand and borrowings under the Credit Agreement.

On October 4, 2018, we issued $300.0 million of Additional 2026 Notes with a coupon rate of 5.875%. The Additional 2026 Notes were issued pursuant to, and are governed by, the same indenture governing the Original 2026 Notes. The Additional 2026 Notes were issued at 100.5% of par, plus accrued interest from August 21, 2018. We 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 $325.0 million in outstanding borrowings under the Credit Agreement, which were incurred in connection with the BLM Acquisition. In December 2018, pursuant to a registered exchange offer, we exchanged substantially all of the 2026 Notes for a like principal amount of 5.875% senior notes due 2026 that have been registered under the Securities Act (the "Notes"). The terms of the Notes are substantially the same as the terms of the 2026 Notes except that the transfer restrictions, registration rights and provisions for additional interest relating to the 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.

In October 2018, the lenders under our Credit Agreement 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. This October 2018 redetermination constituted the regularly scheduled November 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 December 2018, San Mateo 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. The San Mateo Credit Facility, which matures December 19, 2023, includes an accordion feature, which could expand lender commitments to up to $400.0 million. The San Mateo Credit Facility is guaranteed by San Mateo's subsidiaries, secured by substantially all of San Mateo's assets, including real property, and is non-recourse to Matador and its other subsidiaries.

At December 31, 2018, we had (i) $1.05 billion of outstanding Notes, (ii) $40.0 million in borrowings outstanding under the Credit Agreement and (iii) approximately $3.0 million in outstanding letters of credit issued pursuant to the Credit Agreement, and San Mateo had $220.0 million in borrowings outstanding under the San Mateo Credit Facility. At February 26, 2019, we had (x) $1.05 billion of outstanding Notes, (y) $80.0 million in borrowings outstanding under the Credit Agreement and (z) approximately $13.7 million in outstanding letters of credit issued pursuant to the Credit Agreement, and San Mateo had $220.0 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 2019. We plan to operate six contracted drilling rigs drilling primarily oil and natural gas wells in the

Delaware Basin throughout most of 2019. Our 2019 estimated capital expenditure budget consists of $640 to $680 million for D/C/E capital expenditures and $55 to $75 million for midstream capital expenditures, which primarily reflects our proportionate share of San Mateo and San Mateo II's estimated combined 2019 capital expenditures of $180 to $220 million and also accounts for portions of the $50 million capital carry that Five Point is expected to provide to us in conjunction with the formation of San Mateo II. Substantially all of our 2019 estimated capital expenditures will be allocated to the further delineation and development of our leasehold position, to the continued construction of midstream assets and to our participation in certain non-operated well opportunities in the Delaware Basin, with the exception of amounts incurred in 2019 to conclude our South Texas drilling program and 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 2019 Delaware Basin drilling program is expected to focus on the continued development of the Rustler Breaks and Wolf asset areas and the

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further delineation and development of the Antelope Ridge, Jackson Trust, Ranger/Arrowhead and Twin Lakes asset areas as well as the federal leasehold acreage in the western portion of the Antelope Ridge asset area acquired in the BLM Acquisition. 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 12 months. The other three rigs are on short-term contracts with remaining obligations of six 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 further narrow any potential difference between our 2019 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 well as to consider monetizing other assets, such as certain mineral, royalty and non-core 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 2019. 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 2019 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 2019.

Our 2019 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 2019 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 2019 and the hedges we currently have in place. 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 11 to the consolidated financial statements in this Annual Report for a summary of our open derivative financial instruments at December 31, 2018. 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."

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Our cash flows for the years ended December 31, 2018, 2017 and 2016 are presented below.

	Year Ended December 31,		
	2018	2017	2016
(In thousands)			
Net cash provided by operating activities	$608,523	$299,125	$134,086
Net cash used in investing activities	(1,515,253)	(819,284)	(448,739)
Net cash provided by financing activities	888,232	408,499	467,706
Net change in cash	$(18,498)	$(111,660)	$153,053

Cash Flows Provided by Operating Activities

Net cash provided by operating activities increased by $309.4 million to $608.5 million for the year ended December 31, 2018, as compared to net cash provided by operating activities of $299.1 million for the year ended December 31, 2017. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased to $544.1 million for the year ended December 31, 2018 from $324.2 million for the year ended December 31, 2017. This increase was primarily attributable to higher oil and natural gas production and higher oil prices realized during the year ended December 31, 2018, as compared to the year ended December 31, 2017. Changes in our operating assets and liabilities between December 31, 2017 and December 31, 2018 also resulted in a net increase of approximately $89.5 million in net cash provided by operating activities for the year ended December 31, 2018, as compared to the year ended December 31, 2017.

Net cash provided by operating activities increased by $165.0 million to $299.1 million for the year ended December 31, 2017, as compared to net cash provided by operating activities of $134.1 million