CALLON PETROLEUM CO
Form 10-K
February 27, 2019
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 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 001-14039

Callon Petroleum Company
(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	64-0844345 (IRS Employer Identification No.)
1401 Enclave Parkway, Suite 600 Houston, Texas (Address of Principal Executive Offices)	77077 (Zip Code)

281-589-5200
(Registrant's Telephone Number, Including Area Code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	New York Stock Exchange
10.0% Series A Cumulative Preferred Stock	New York Stock Exchange

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

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

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

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

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

Indicate by check mark 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.

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

Large accelerated filer Accelerated filer Non-accelerated filer

Smaller reporting company Emerging growth company

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes No

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2018 was approximately $2,426,644,330.

The Registrant had 227,875,828 shares of common stock outstanding as of February 22, 2019.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Callon Petroleum Company (to be filed no later than 120 days after December 31, 2018) relating to the Annual Meeting of Stockholders to be held on May 9, 2019, which are incorporated into Part III of this Form 10-K.

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Special Note Regarding Forward Looking Statements

This report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 (the “Securities Act”), as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements in this Form 10-K by words such as “anticipate,” “project,” “intend,” “estimate,” “expect,” “believe,” “predict,” “budget,” “pro “goal,” “plan,” “forecast,” “target” or similar expressions.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future are forward-looking statements, including such things as:

- our oil and natural gas reserve quantities, and the discounted present value of these reserves;
- the amount and nature of our capital expenditures;
- our future drilling and development plans and our potential drilling locations;
- the timing and amount of future capital and operating costs;
- production decline rates from our wells being greater than expected;
- commodity price risk management activities and the impact on our average realized prices;
- business strategies and plans of management;
- our ability to consummate and efficiently integrate recent acquisitions; and
- prospect development and property acquisitions.

Some of the risks, which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements, include:

- general economic conditions including the availability of credit and access to existing lines of credit;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- impairments;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment, waste and water disposal infrastructure, and personnel;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- the potential impact of future drilling on production from existing wells
- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers’ supply;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business including those related to climate change and greenhouse gases;
- the impact of government regulation, including regulation of hydraulic fracturing and water disposal wells;
- any increase in severance or similar taxes;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties;
- cyberattacks on the Company or on systems and infrastructure used by the oil and natural gas industry;
- weather conditions; and
- any other factors listed in the reports we have filed and may file with the SEC.

We caution you that the forward-looking statements contained in this Form 10-K are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, the risks described in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2018 (the "2018 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto.

Should one or more of the risks or uncertainties described above or in our 2018 Annual Report on Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. Any forward-looking statement speaks only as of the date of which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except required by applicable law.

In addition, we caution that reserve engineering is a process of estimating oil and natural gas accumulated underground and cannot be measured exactly. Accuracy of reserve estimates depend on a number of factors including data available at the point in time, engineering interpretation of the data, and assumptions used by the reserve engineers as it relates to price and cost estimates and recoverability. New results of drilling, testing, and production history may result in revisions of previous estimates and, if significant, would impact future development plans. As such, reserve estimates may differ from actual results of oil and natural gas quantities ultimately recovered.

Except as required by applicable law, all forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

GLOSSARY OF CERTAIN TERMS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their prescribed meanings when used in this report. As used in this document:

- ARO: asset retirement obligation.
- ASU: accounting standards update.
- Bbl or Bbls: barrel or barrels of oil or natural gas liquids.
- BOE: barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of natural gas. The ratio of one barrel of oil or NGL to six Mcf of natural gas is commonly used in the industry and represents the approximate energy equivalence of oil or NGLs to natural gas, and does not represent the economic equivalency of oil and NGLs to natural gas. The sales price of a barrel of oil or NGLs is considerably higher than the sales price of six Mcf of natural gas.
- BOE/d: BOE per day.
- BLM: Bureau of Land Management.
- Btu: a British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- Completion: the process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.
- Cushing: an oil delivery point that serves as the benchmark oil price for West Texas Intermediate.
- DOI: Department of Interior.
- EPA: United States Environmental Protection Agency.
- FASB: Financial Accounting Standards Board.
- GAAP: Generally Accepted Accounting Principles in the United States.
- Henry Hub: a natural gas pipeline delivery point that serves as the benchmark natural gas price underlying NYMEX natural gas futures contracts.
- Horizontal drilling: a drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at an angle within a specified interval.
- GHG: greenhouse gases.
- LIBOR: London Interbank Offered Rate.
- LOE: lease operating expense.
- MBbls: thousand barrels of oil.
- MBOE: thousand BOE.
- Mcf: thousand cubic feet of natural gas.
- MMBOE: million BOE.
- MMBtu: million Btu.
- MMcf: million cubic feet of natural gas.
- NGL or NGLs: natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.
- NYMEX: New York Mercantile Exchange.
- Oil: includes crude oil and condensate.
- OPEC: Organization of Petroleum Exporting Countries.
- PDPs: proved developed producing reserves.
- PUDs: proved undeveloped reserves.
- Realized price: the cash market price less all expected quality, transportation and demand adjustments.
- Royalty interest: an interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development.
- RSU: restricted stock units.
- SEC: United States Securities and Exchange Commission.
- Waha: a natural gas delivery point in West Texas that serves as the benchmark for natural gas.

- Working interest: an operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
- WTI: West Texas Intermediate grade crude oil, used as a pricing benchmark for sales contracts and NYMEX oil futures contracts.

With respect to information relating to our working interest in wells or acreage, "net" oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I.
ITEMS 1 and 2 – Business and Properties

Overview

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and natural gas properties since 1950. As used herein, the "Company," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise. We were incorporated in the state of Delaware in 1994.

We are an independent oil and natural gas company focused on the acquisition and development of unconventional onshore oil and natural gas reserves in the Permian Basin. The Permian Basin is located in West Texas and southeastern New Mexico and is comprised of three primary sub-basins: the Midland Basin, the Delaware Basin, and the Central Basin Platform. We have historically been focused on the Midland Basin and entered the Delaware Basin through an acquisition completed in February 2017. We further expanded our presence in the Delaware Basin through our acquisitions in 2018.

Our drilling activity during 2018 was predominantly focused on the horizontal development of several prospective intervals in the Midland and Delaware Basins, including multiple levels of the Wolfcamp formation and the Lower Spraberry shales. As a result of our horizontal development efforts and contributions from acquisitions, our net daily production for calendar year 2018 as compared to calendar year 2017 grew approximately 44% to 32,926 BOE/d (approximately 79% oil). For the year ended December 31, 2018, our net proved reserve volumes increased 74% as compared to the year ended December 31, 2017, to 238.5 MMBOE, comprised of 76% oil (180.1 MMBbls) and 24% natural gas (350.5 Bcf). Approximately 54% of our net proved year-end 2018 reserves were proved developed on a BOE basis.

We intend to grow our reserves and production through the drilling and development of our multi-year inventory of identified drilling locations. We will also seek to grow our inventory of locations through delineation of emerging zones and selective "bolt-on" acquisition and leasing programs in areas complementary to our core operating areas.

Our Business Strategy

Our principal objective is to enhance shareholder value through capital efficient growth in proved reserves and associated production and cash flows while acting as a responsible corporate citizen in the areas in which we operate. Key elements of the execution of this strategy include:

- Optimizing the development of our multi-zone resource base through thoughtful plans of depletion that are educated by extensive analysis of subsurface data and empirical well results;
- Maintaining strong cash margins per unit of production through cost management and proactive investment in production infrastructure;
- Improving the capital efficiency of our operations in terms of both well productivity and capital outlays, including supporting facilities;
- Maturing our asset base into a sustainable operating model for profitable reinvestment of cash flows for attractive, long-term returns on capital;
- Growing our inventory of well locations through delineation of emerging targets on our existing acreage positions and selective acquisitions of leasehold rights and mineral interests in areas complementary to our existing core operating areas; and
- Preserving a strong financial position, focusing on appropriate capital allocation decisions under various commodity pricing scenarios, prudent risk management and robust liquidity.

Our Strengths

We believe the following attributes position Callon to achieve its objectives:

- Strong Foundation - Reputation as a safe and responsible operator built over several decades in the oil and gas industry;
- Quality Assets - High quality Permian Basin asset base with several years of proven well results from multiple target zones that benefit from early investments in critical supporting infrastructure including sustainable investments in water recycling;
- Operational Control - High degree of operational control that allows us to efficiently maximize value through long-term and daily decisions that drive our strategy;
- Talented Workforce - Seasoned employee base that has continued to benefit from the hiring of quality employees across various disciplines that have been integrated into our unifying culture.

Oil and Natural Gas Properties

Permian Basin

As of December 31, 2018, we owned 84,705 net leasehold acreage in the Permian Basin, all of which was located in the Midland and Delaware Basins. Average net production from our Permian Basin properties increased 44% to 32,926 BOE/d in 2018 from
22,940 BOE/d in 2017. The following sets forth certain information about our major operating areas in the Permian Basin as of December 31, 2018:

		Producing Wells				Producing
		Horizontal		Vertical		Horizontal Flow
	Net Acres	Gross	Net	Gross	Net	Unit Zones
Midland Basin	39,534	250	186.9	304	248.2	Middle Spraberry, Lower Spraberry, Wolfcamp A, Wolfcamp B, Wolfcamp C
Delaware Basin	45,171	216	176.7	126	76.3	Third Bone Spring, Wolfcamp A, Wolfcamp B, Wolfcamp C
Total Permian Basin	84,705	466	363.6	430	324.5	

Reserve Data

As of December 31, 2018, our estimated net proved reserves grew 74% from prior year-end, totaling 238.5 MMBOE and included 180.1 MMBbls of oil and 350.5 Bcf of natural gas with a standardized measure of discounted future net cash flows of $2.9 billion. Oil constituted approximately 76% of our total estimated equivalent net proved reserves and approximately 72% of our total estimated equivalent proved developed reserves. We added 85 MMBOE of new reserves in extensions and discoveries through our development efforts in our operating areas, where we drilled a total of 70 gross (57.5 net) wells. We purchased reserves in place of 39.7 MMBOE from the Delaware Asset Acquisition as well as bolt-on acquisitions completed within the Permian Basin and reduced our estimated net proved reserves through net revisions of previous estimates of 2.0 MMBOE and reclassifications of 9.1 MMBOE to probable reserves. Our net revisions of previous estimates were primarily related to technical revisions of proved undeveloped reserves. We reclassified 19 PUD locations to probable reserves, primarily due to acreage trades and changes in our development plan, including larger pad development concepts and co-development of zones. These changes resulted in the anticipated drilling of PUD locations being moved beyond five years from initial booking. The changes in our proved reserves are as follows (in MBOE):

Proved reserves:	
Reserves at December 31, 2017	136,974
Extensions and discoveries	84,955
Purchase of reserves in place	39,683
Revisions to previous estimates	(2,021)
Reclassifications due to changes in development plan	(9,065)
Production	(12,018)
Reserves at December 31, 2018	238,508

Annually, the Company reviews its PUDs to ensure appropriate plans exist for development of this reserve category. PUD reserves are recorded only if the Company has plans to convert these reserves into PDPs within five years of the date they are first recorded. Our development plans include the allocation of capital to projects included within our 2019 capital budget and, in subsequent years, the allocation of capital within our long-range business plan to convert PUDs to PDPs within this five year period. In general, our 2019 capital budget and our long-range capital plans are primarily governed by our expectations of internally generated cash flow, borrowing availability under our senior secured revolving credit facility ("Credit Facility") and corporate credit metrics. Reserve calculations at any end-of-year period are representative of our development plans at that time. Changes in commodity pricing, oilfield service costs and availability, and other economic factors may lead to changes in development plans. The following table shows changes in proved undeveloped reserves for 2018 (in MBOE):

Proved undeveloped reserves:	
Reserves at December 31, 2017	67,656
Extensions and discoveries	56,710
Purchases of reserves in place	9,861
Transfers to proved developed	(11,075)
Revisions of previous estimates	(4,184)
Reclassifications due to changes in development plan	(9,065)
Reserves at December 31, 2018	109,903

A breakdown by commodity of our proved oil and natural gas reserves follows:

	For the Year Ended December 31,		
Proved developed reserves:	2018	2017	2016
Oil (MBbls):	92,202	51,920	32,920
Natural gas (MMcf):	218,417	104,389	61,871
MBOE:	128,605	69,318	43,232
Proved undeveloped reserves:			
Oil (MBbls):	87,895	55,152	38,225
Natural gas (MMcf):	132,049	75,021	60,740
MBOE:	109,903	67,656	48,348
Total proved reserves:			
Oil (MBbls):	180,097	107,072	71,145
Natural gas (MMcf):	350,466	179,410	122,611
MBOE:	238,508	136,974	91,580

Controls Over Reserve Estimates

Compliance as it relates to reporting the Company's reserves is the responsibility of our Chief Operating Officer, who is also our principal engineer. Until December 2018, our Chief Operating Officer was Gary A. Newberry who had over 36 years of industry experience, including 30 years as a manager, and holds a degree in Petroleum Engineering. In December 2018, Jeffrey S. Balmer became our Chief Operating Officer upon Mr. Newberry's retirement from the Company. Dr. Balmer has over 30 years of operations and industry experience. In addition to his years of experience, Dr. Balmer holds B.S. and Ph.D. degrees in Petroleum Engineering, in addition to a M.S. in Environmental and Planning Engineering, and is experienced in asset evaluation and management.

Callon's controls over reserve estimates included retaining DeGolyer and MacNaughton, a Texas registered engineering firm, as our Reserve Engineering Firm. The Company provided to DeGolyer and MacNaughton information about our oil and gas properties, including production profiles, prices and costs, and DeGolyer and MacNaughton prepared its own estimates of the reserves attributable to the Company's properties. All of the information regarding 2018, 2017 and 2016 reserves in this annual report is derived from DeGolyer and MacNaughton's report. DeGolyer and MacNaughton's reserve report letter is included as an exhibit to this annual report. The principal engineer at DeGolyer and MacNaughton, who certified the Company's reserve estimates, has over 34 years of experience in the oil and gas industry and is a Texas Licensed Professional Engineer. Further professional qualifications include a degree in petroleum engineering and membership in the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

To further enhance the control environment over the reserve estimation process, our Strategic Planning and Reserves Committee, an independent committee of the Board of Directors, assists management and the Board with its oversight of the integrity of the determination of the Company's oil and natural gas reserves and the work of our Reserve Engineering Firm. The Committee's charter also specifies that the Committee shall perform, in consultation with the

Company's management and senior reserves and reservoir engineering personnel, the following responsibilities:

- Oversee the appointment, qualification, independence, compensation and retention of the Reserve Engineering Firm engaged by the Company (including resolution of material disagreements between management and the Reserve Engineering Firm regarding reserve determination) for the purpose of preparing or issuing an annual reserve report. The Committee shall review any proposed changes in the appointment of the Reserve Engineering Firm, determine the reasons for such proposal, and whether there have been any disputes between the Reserve Engineering Firm and management.
- Review the Company's significant reserves engineering principles and any material changes thereto, and any proposed changes in reserves engineering standards and principles which have, or may have, a material impact on the Company's reserves disclosure.
- Review with management and the Reserve Engineering Firm the proved reserves of the Company, and, if appropriate, the probable reserves, possible reserves and the total reserves of the Company, including: (i) reviewing significant changes from

prior period reports; (ii) reviewing key assumptions used or relied upon by the Reserve Engineering Firm; (iii) evaluating the quality of the reserve estimates prepared by both the Reserve Engineering Firm and the Company relative to the Company's peers in the industry; and (iv) reviewing any material reserves adjustments and significant differences between the Company's and Reserve Engineering Firm's estimates.

- If the Committee deems it necessary, it shall meet in executive session with the Reserve Engineering Firm to discuss the oil and gas reserve determination process and related public disclosures, and any other matters of concern in respect of the evaluation of the reserves.

During our last fiscal year, we filed no reports with other federal agencies which contain an estimate of total proved net oil and natural gas reserves.

See Supplemental Information on Oil and Natural Gas Operations in Item 8 - Financial Statements and Supplementary Data for additional information regarding our estimated net proved reserves and our estimated future net cash flows and discounted future net cash flows from proved reserves.

2019 Capital Budget

Our operational capital budget for 2019 has been established in the range of $500 to $525 million on an accrual, or GAAP, basis, running an average of five drilling rigs to support larger, and more efficient, multi-well pad development. Of this range, approximately 15% is comprised of infrastructure and facilities capital.

As part of our 2019 operated horizontal drilling program, we expect to place 47 to 49 net wells on production with an increase of approximately 15% in average net lateral length as compared to the 2018 program.

In addition to the operational capital expenditures budget, which includes well costs, facilities and infrastructure capital, and surface land purchases, we budgeted an estimated $25 to $30 million for capitalized general and administrative expenses.

Our revenues, earnings, liquidity and ability to grow are substantially dependent on the prices we receive for, and our ability to develop, our reserves of oil and natural gas. We believe the long-term outlook for our business is favorable due to our resource base, low cost structure, financial strength, risk management, and disciplined investment of capital. We monitor current and expected market conditions, including the commodity price environment, and our liquidity needs and may adjust our capital investment plan accordingly.

Exploration and Development Activities

Our 2018 total capital expenditures, including acquisitions, on a cash basis were $1,324.1 million, of which $546.1 million consisted of operational capital expenditures, including drilling and completion and facilities and infrastructure expenditures.

For the year ended December 31, 2018, we drilled 70 gross (57.5 net) horizontal wells, completed 65 gross (53.1 net) horizontal wells and had 11 gross (9.5 net) horizontal wells awaiting completion.

The following table sets forth the Company's drilled wells, none of which were natural gas wells, nor nonproductive wells for the periods reflected:

	2018		2017 [(a)]		2016	
	Gross	Net	Gross	Net	Gross	Net
Oil wells						
Development [(b)]	15	12.8	15	10.7	9	4.9

Exploratory [c]	55	44.7	33	26.5	20	16.0
Total	70	57.5	48	37.2	29	20.9

(a) Does not include one gross (0.97 net) nonproductive exploratory well.

(b) A development well is a well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

(c) An exploratory well is a well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Productive Wells

As of December 31, 2018, we had 896 gross (688.1 net) working interest oil wells, three gross (0.1 net) royalty interest oil wells and no natural gas wells. A well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas reserves on a BOE basis. However, most of our wells produce both oil and natural gas.

Production Volumes, Average Sales Prices and Operating Costs

The following tables set forth certain information regarding the production volumes and average sales prices received for, and average production costs associated with, the Company's sale of oil and natural gas for the periods indicated (dollars in thousands, except per unit data).

	For the Year Ended December 31,		
	2018	2017	2016
Production			
Midland Basin			
Oil (MBbls)	7,557	5,871	4,280
Natural gas (MMcf)	13,042	10,061	7,758
Total Midland Basin (MBOE)	9,731	7,548	5,573
Delaware Basin			
Oil (MBbls)	1,886	686	—
Natural gas (MMcf)	2,405	835	—
Total Delaware Basin (MBOE)	2,287	825	—
Total oil (MBbls)	9,443	6,557	4,280
Total natural gas (MMcf)	15,447	10,896	7,758
Total (MBOE)	12,018	8,373	5,573

	For the Year Ended December 31,		
	2018	2017	2016
Revenues			
Oil revenue	$530,898	$322,374	$177,652
Natural gas revenue	56,726	44,100	23,199
Total	$587,624	$366,474	$200,851
Operating costs			
Lease operating expense	$69,180	$49,907	$38,353
Production taxes	35,755	22,396	11,870
Total	$104,935	$72,303	$50,223
Average realized sales price (excluding impact of settled derivatives)			
Oil (per Bbl)	$56.22	$49.16	$41.51
Natural gas (per Mcf)	3.67	4.05	2.99
Total (per BOE)	48.90	43.77	36.04
Average realized sales price (including impact of settled derivatives)			
Oil (per Bbl)	$53.31	$47.78	$45.67
Natural gas (per Mcf)	3.69	4.10	3.00
Total (per BOE)	46.63	42.76	39.25
Operating costs per BOE			
Lease operating expense	$5.76	$5.96	$6.88
Production taxes	2.98	2.67	2.13

Total	$8.74	$8.63	$9.01

Major Customers

Our production is sold generally on month-to-month contracts at prevailing prices. The following table identifies customers to whom we sold a significant percentage of our total oil and natural gas production, on an equivalent basis, during each of the 12-month periods indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Rio Energy International, Inc.	28 %	17 %	— %
Plains Marketing, L.P.	21 %	29 %	16 %
Enterprise Crude Oil, LLC	14 %	18 %	43 %
Shell Trading Company	8 %	9 %	18 %
Trafigura Trading, LLC	6 %	— %	— %
Other	23 %	27 %	23 %
Total	100%	100%	100%

Because alternative purchasers of oil and natural gas are readily available, the Company believes that the loss of any of these purchasers would not result in a material adverse effect on its ability to market future oil and natural gas production. In order to mitigate potential exposure to credit risk, we may require from time to time for our customers to provide financial security.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2018.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin [(a)]	104,816	73,989	23,890	10,716	128,706	84,705
Other	936	200	188	55	1,124	255
Total	105,752	74,189	24,078	10,771	129,830	84,960

(a) A portion of our Permian Basin acreage, which we have included in our development plans, requires continuous drilling to hold the acreage, though the cost to renew this acreage, if necessary, is not considered material.

The following table sets forth as of December 31, 2018 the number of our leased gross and net undeveloped acres in the Permian Basin that will expire over the next three years unless production begins before lease expiration dates. Gross amounts may be more than net amounts in a particular year due to timing of expirations.

	Net				Gross
	2019	2020	2021	Total	Total
Permian Basin	5,492	2,878	568	8,938	19,798

The expiring acreage set forth in the table above accounts for approximately 83% of our net undeveloped acreage (10,771 total net acres). We are continually engaged in a combination of drilling and development and discussions with mineral lessors for lease extensions, renewals, new drilling and development units and new leases to address any potential expiration of undeveloped acreage that occurs in the normal course of our business.

Other

Industry Segment and Geographic Information

For segment reporting purposes, the Company considers all of the current development and operating areas to be one reportable segment: the development and production of oil and natural gas. All of the Company’s assets and operations are located within the United States, and all of the production revenues generated from operations are contracted and sold to customers located in the United States.

Title to Properties

The Company believes that the title to its oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. The Company’s properties are potentially subject to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and natural gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements; farm-out agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements;
- pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect the Company’s rights to production revenues, these characteristics have been taken into account in calculating Callon’s net revenue interests and in estimating the size and value of its reserves. The Company believes that the burdens and obligations affecting our properties are typical within the industry for properties of the kind owned by Callon.

Seasonality of Business

Weather conditions and seasonality affect the demand for and prices of, oil and natural gas. Due to these fluctuations, results of operations for quarterly interim periods may not be indicative of the results realized on an annual basis.

Competition

The Company operates in the oil and natural gas industry, which is highly competitive. The Company’s business experiences strong competition from a number of parties that may range from small independent producers to major integrated companies. Competition affects the Company’s ability to acquire additional properties and resources necessary to develop assets. In higher commodity pricing environments, competition also exists in the form of contracting for drilling, pumping, and workover equipment, and securing skilled personnel to both develop and operate existing assets. Many of the competitors mentioned above may be able to pay for more sought-after properties or access equipment, infrastructure, or personnel. The industry also experiences, from time to time, shortages in resources such as the availability of drilling and workover rigs, other equipment, pipes and materials, infrastructures, and skilled personnel, all of which can delay development, exploration, and workover activities as well as result in significant cost increases.

Insurance

In accordance with industry practice, the Company maintains insurance against some, but not all, of the operating risks to which its business is exposed. While not all inclusive, the Company’s insurance policies generally protect against bodily injury and property damage, pollution and other environmental damages, employee benefits, employee injury and control of well insurance for its exploration and production operations.

The Company enters into master service agreements with its third-party contractors, including hydraulic fracturing contractors, in which they agree to indemnify the Company for injuries and deaths of the service provider’s employees, as well as contractors and subcontractors hired by the service provider. Similarly, the Company generally agrees to indemnify each third-party contractor against claims made by employees of the Company and the Company’s other contractors. Additionally, each party generally is responsible for damage to its own property. The Company re-evaluates the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and natural gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable.

While based on the Company’s risk analysis we believe that we are properly insured, no assurance can be given that the Company will be able to maintain insurance in the future at rates that it considers reasonable. In such circumstances, the Company may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

Corporate Offices

The Company’s headquarters are located in Houston, Texas, in a building with office space leased by the Company. We own an office building in Natchez, Mississippi and lease and own offices in the Midland, Texas area. Because alternative locations to our leased spaces are readily available, the replacement of any of our leased offices would not result in material expenditures.

Employees

Callon had 218 employees as of December 31, 2018. None of the Company's employees are currently represented by a union, and the Company believes that it has good relations with its employees.

Regulations

General. Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. Legislation and regulation affecting the entire oil and natural gas industry is continuously being reviewed for potential revision. Some of these requirements carry substantial penalties for failure to comply.

Exploration and Production. Our operations are subject to federal, state and local regulations that include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds and letters of credit) covering drilling and well operations. Other activities subject to regulation are:

- the location and spacing of wells;
- the method of drilling and completing and operating wells;
- the rate and method of production;
- the surface use and restoration of properties upon which wells are drilled and other exploration activities;
- notice to surface owners and other third parties;
- the venting or flaring of natural gas;
- the plugging and abandoning of wells;
- the discharge of contaminants into water and the emission of contaminants into air;
- the disposal of fluids used or other wastes obtained in connection with operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Our sales of oil and natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. If these regulations change, we could face higher transmission costs for our production and, possibly, reduced access to transmission capacity.

Various proposals and proceedings that might affect the petroleum industry are pending before Congress, the Federal Energy Regulatory Commission, or FERC, various state legislatures, and the courts. Historically, the industry has been heavily regulated and we can offer you no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue nor can we predict what effect such proposals or proceedings may have on our operations.

We do not currently anticipate that compliance with existing laws and regulations governing exploration and production will have a significantly adverse effect upon our capital expenditures, earnings or competitive position.

Environmental Matters and Regulation. Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the EPA, issue regulations which often require difficult and costly compliance measures. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relating to our owned or operated facilities. Violations of environmental laws could result in administrative, civil or criminal fines and injunctive relief. The strict and joint and several liability nature of certain such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons, air emissions or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. In recent years, the oil and natural gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. Although such laws and regulations can increase the cost of planning, designing, installing and operating our facilities, it is anticipated that, absent the occurrence of an extraordinary event, compliance with them will not have a material effect upon our operations, capital expenditures, earnings or competitive position in the marketplace.

Waste Handling. The Resource Conservation and Recovery Act (“RCRA”), as amended, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of oil and natural gas are exempt from regulation as hazardous wastes under RCRA and its state analogs, it is possible that some wastes we generate presently or in the future may be subject to regulation under RCRA and state analogs. Additionally, we cannot assure you that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as “hazardous wastes.” Additionally, following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency’s failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of wastes associated with oil and natural gas exploration and production could increase our costs to manage and dispose of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), imposes joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or so–called potentially responsible parties (“PRPs”) include the current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes.

Although CERCLA generally exempts “petroleum” from the definition of hazardous substance, in the course of our operations, we have generated and will generate wastes that may fall within CERCLA’s definition of hazardous substance and may have disposed of these wastes at disposal sites owned and operated by others. Comparable state statutes may not provide a comparable exemption for petroleum. We may also be the owner or operator of sites on which hazardous substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA; we also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. In the event contamination is discovered at a site on which we are or have been an owner or operator or to which we sent hazardous substances, we could be liable for the costs of investigation and remediation and natural resources damages.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, and for water disposal, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including offsite locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. In the future, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the “Clean Water Act,” the Safe Drinking Water Act, the Oil Pollution Act (“OPA”), and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States (a term broadly defined to include, among other things, certain wetlands), as well as state waters for analogous state programs. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or applicable state analog. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit from the U.S. Army Corps of Engineers. The EPA issued a final rule on the federal jurisdictional reach over waters of the United States in 2015. The rule is the subject of various legal challenges. Recently, the EPA proposed to repeal that rule and re-codify the pre-2015 rule while it revises the definition of “waters of the United States,” creating uncertainty regarding federal jurisdiction over waters of the United States.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, as amended, and comparable state and local laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and modified and existing facilities may be required to obtain additional permits. As a result, we may need to incur capital costs in order to remain in compliance. Obtaining or renewing permits also has the potential to delay the development of oil and natural gas projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties and seek injunctive relief for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations.

On June 3, 2016, the EPA expanded its regulatory coverage in the oil and natural gas industry with additional regulated equipment categories, and the addition of new rules limiting methane emissions from new or modified sites and equipment. Although the EPA attempted to suspend enforcement of the methane rule, this action was ruled improper by the U.S. Court of Appeals for the D.C. Circuit on July 2, 2017. Subsequently, in September 2018, the EPA issued a proposed rulemaking that could substantially change the obligations associated with methane emissions, limiting obligations for the oil and natural gas industry. That rulemaking has not been finalized and, therefore, future obligations continue to remain uncertain.

Climate Change. Numerous reports from scientific and governmental bodies such as the United Nations Intergovernmental Panel on Climate Change have expressed heightened concerns about the impacts of human activity, especially fossil fuel combustion, on the global climate. In turn, governments and civil society are increasingly focused on limiting the emissions of greenhouse gases, including emissions of carbon dioxide from the use of oil and natural gas.

In December 2015, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change resulted in 195 countries, including the United States, coming together to develop the so-called “Paris Agreement,” which calls for the parties to undertake “ambitious efforts” to limit the average global temperature. The Agreement went into effect on November 4, 2016, and establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions. While the United States announced that it would withdraw from the Paris Agreement on June 1, 2017, given the requirements of the withdrawal process the earliest possible exit would be November 2020. Certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. In addition, legislation has from time to time been introduced in Congress that would establish measures restricting GHG emissions in the United States, and a number of states have begun taking actions to control and/or reduce emissions of GHGs.

Any legislation or regulatory programs at the federal, state, or city levels designed to reduce GHG emissions could 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 GHGs could have an adverse effect on our business, financial condition and results of operations. Moreover, incentives to conserve energy or use alternative energy sources, such as policies designed to increase utilization of zero-emissions or electric vehicles, as a means of addressing climate change could reduce demand for the oil and natural gas we produce.

In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the Supreme Court struck down the permitting requirements, it upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants.

The EPA has established GHG reporting requirements for certain sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions. Although these requirements do not limit the amount of GHGs that can be emitted, they do require us to incur costs to monitor, keep records of, and report GHG emissions associated with our operations.

Parties concerned about the potential effects of climate change have also directed their attention at sources of financing for energy companies, which has resulted in certain financial institutions, funds and other capital providers restricting or eliminating their investment in oil and natural gas activities. In addition, some parties have initiated public nuisance claims under federal or state common law against certain companies involved in the production of oil and natural gas. Although our business is not a party to any such litigation, we could be named in actions making similar allegations, which could lead to costs and materially impact our financial condition in an adverse way.

Finally, most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of droughts, storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves.

Regulation of Hydraulic Fracturing. Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act ("SDWA") regulates the underground injection of substances through the Underground Injection Control ("UIC") program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions and not at the federal level, as the SDWA expressly excludes regulation of these fracturing activities (except where diesel is a component of the fracturing fluid, as further discussed below). Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing has been proposed in past legislative sessions but has not passed.

The EPA, however, issued guidance on permitting hydraulic fracturing that uses fluids containing diesel fuel under the UIC program, specifically as "Class II" UIC wells. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," including water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. This report could result in additional regulatory scrutiny that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and business. Further, on June 28, 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants.

On June 3, 2016, the EPA adopted regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA’s rule package included New Source Performance Standards (“NSPS”) for hydraulically fractured natural gas and oil wells to address emissions of sulfur dioxide, volatile organic compounds (“VOCs”) and methane, with a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule sought to achieve a 95% reduction in VOCs and methane emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured gas and oil wells newly constructed or refractured. The rules also established specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. Notably, on October 15, 2018, the EPA published a proposed rule that would make a series of revisions to the 2016 NSPS; these revisions have yet to be finalized.

Several states, including Texas, and some municipalities, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, Texas law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") for disclosure on a website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission.

Additionally, some states, localities and local regulatory districts have adopted or have considered adopting regulations to limit, and in some cases impose a moratorium on, hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; or restrictions on access to, and usage of, water. Further, there has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the U.S. implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations of harm. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of potential federal or state legislation governing hydraulic fracturing.

Surface Damage Statutes ("SDAs"). In addition, a number of states and some tribal nations have enacted SDAs. These laws are designed to compensate for damage caused by oil and gas development operations. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain binding requirements for payments by the operator to surface owners/users in connection with exploration and operating activities in addition to bonding requirements to compensate for damages to the surface as a result of such activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

National Environmental Policy Act and Endangered Species Act. Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act ("NEPA"), which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Recent litigation by environmental non-governmental organizations has alleged that the Environmental Assessments for certain oil and natural gas projects violated NEPA by failing to account for climate change and the greenhouse gas emissions impacts of such projects. To the extent that our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA, this process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' or its 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 further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If the Company was to have a portion of its leases designated as critical or suitable habitat or a protected species were located on a lease, it may adversely impact the value of the affected leases.

Other Regulation of the Oil and Natural Gas Industry. The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other similar companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the rates and other terms for access to oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas sales prices are currently unregulated, the federal government historically has been active in the area of oil and natural gas sales regulation. We cannot predict whether new legislation to regulate oil and natural gas sales might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate, oil and natural gas liquids are not currently regulated and are made at market prices.

Exports of US Oil Production and Natural Gas Production. In December 2015, the federal government ended its decades-old prohibition of exports of oil produced in the lower 48 states of the US. As a result, exports of U.S. oil have increased significantly, reinforcing the general perception in the industry that the end of the U.S. export ban was positive for producers of U.S. oil. In addition, the U.S. Department of Energy ("DOE") authorizes exports of natural gas, including exports of natural gas by pipelines connecting U.S. natural gas production to pipelines in Mexico, and the export of liquefied natural gas ("LNG") through LNG export facilities, the construction of which are regulated by FERC. Since 2016, natural gas produced in the lower 48 states of the U.S. has been exported as LNG from LNG export facilities being developed and constructed in the U.S. Gulf Coast region. This export capacity has steadily increased, and is expected to continue on that trajectory. The general perception in the industry is that this sustained growth in exports will be a positive development for producers of U.S. natural gas.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affecting the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Some state agencies and municipalities require bonds or other financial assurances to support those obligations.

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales," which include all of our sales of our own production. Under the Energy Policy Act of 2005 ("EPAct"), FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

Under the EPAct Congress amended the Natural Gas Act ("NGA") to give FERC substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties. EPAct also amended the NGA to authorize FERC to "facilitate transparency in markets for the sale or transportation of physical natural gas in interstate commerce," pursuant to which authorization FERC now requires natural gas wholesale market participants, including a number of entities that may not otherwise be subject to FERC's traditional NGA jurisdiction, to report information annually to FERC concerning their natural gas sales and purchases. FERC requires any wholesale market participant that sells 2.2 million MMBtus or more annually in "reportable" natural gas sales to provide a report, known as FERC Form 552, to FERC. Reportable natural gas sales include sales of natural gas that utilize a daily or monthly gas price index, contribute to index price formation, or could contribute to index price formation, such as fixed price transactions for next-day or next-month delivery.

FERC also regulates interstate natural gas transportation rates, terms and conditions of natural gas transportation service, and the terms under which we as a shipper may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and for the release of our excess, if any, natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC's current regulatory regime, interstate transportation services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. The FERC-regulated tariffs, under which interstate pipelines provide such open-access transportation service, contain strict limits on the means by which a shipper releases its pipeline capacity to another potential shipper, which provisions include FERC's "shipper-must-have-title" rule. Violations by a shipper (i.e., a pipeline customer) of FERC's capacity release rules or shipper-must-have-title rule could subject a shipper to substantial penalties from FERC.

With respect to its regulation of natural gas pipelines under the NGA, FERC has not generally required the applicant for construction of a new interstate natural gas pipeline to produce evidence of the GHG emissions of the proposed pipeline's customers. In August 2017, the U.S. Circuit Court of Appeals for the DC Circuit issued a decision remanding a natural gas pipeline certificate application to FERC, which required FERC to revise its environmental impact statement for the proposed pipeline to take into account GHG carbon emissions from downstream power plants using natural gas transported by the new pipeline. It is too early to determine the impacts of this Court decision, but it could be significant.

Gathering service, which occurs on pipeline facilities located upstream of FERC-jurisdictional interstate transportation services, is regulated by the states onshore and in state waters. Depending on changes in the function performed by particular pipeline facilities, FERC has in the past reclassified certain FERC-jurisdictional transportation facilities as non-jurisdictional gathering facilities and FERC has reclassified certain non-jurisdictional gathering facilities as FERC-jurisdictional transportation facilities. Any such changes could result in an increase to our costs of transporting gas to point-of-sale locations.

The pipelines used to gather and transport natural gas being produced by the Company are also subject to regulation by the U.S. Department of Transportation ("DOT") under the Natural Gas Pipeline Safety Act of 1968, as amended

(“NGPSA”), the Pipeline Safety Act of 1992, as reauthorized and amended (“Pipeline Safety Act”), and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The DOT Pipeline and Hazardous Materials Safety Administration (“PHMSA”) has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In addition, PHMSA had initially considered regulations regarding, among other things, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements. In October 2015, PHMSA issued proposed new safety regulations for hazardous liquid pipelines, including a requirement that all hazardous liquid pipelines have a system for detecting leaks and that operators address affected pipelines following extreme weather events or natural disasters. On January 13, 2017, these proposed regulations were finalized; however, the rule was subsequently withdrawn by PHMSA on January 24, 2017. The future disposition of these potential new requirements remains uncertain.

Oil and NGLs Sales and Transportation. Sales of oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

The Company's sales of oil and natural gas liquids are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil and natural gas liquids by pipelines are regulated by FERC under the Interstate Commerce Act. FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil and natural gas liquids pipelines to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil and natural gas liquids pipeline rates. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate common carrier oil pipelines must provide service on a non-discriminatory basis under the Interstate Commerce Act ("ICA"), which is administered by FERC. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

In addition, FERC issued a declaratory order in November 2017, involving a marketing affiliate of an oil pipeline, which held that certain arrangements between an oil pipeline and its marketing affiliate would violate the ICA's anti-discrimination provisions. FERC held that providing transportation service to affiliates at what is essentially the variable cost of the movement, while requiring non-affiliated shippers to pay the filed tariff rate, would violate the ICA. Rehearing has been sought of this FERC order by various pipelines. It is too recent an event to determine the impact this FERC order may have on oil pipelines, their marketing affiliates, and the price of oil and other liquids transported by such pipelines.

Any transportation of the Company's oil, natural gas liquids and purity components (ethane, propane, butane, iso-butane, and natural gasoline) by rail is also subject to regulation by the DOT's PHMSA and the DOT's Federal Railroad Administration ("FRA") under the Hazardous Materials Regulations at 49 CFR Parts 171-180, including Emergency Orders by the FRA regulations initially established on May 8, 2015 by PHMSA, arising due to the consequences of train accidents and the increase in the rail transportation of flammable liquids; PHMSA regulations were subsequently amended to remove certain requirements on September 25, 2018.

On January 13, 2017, PHMSA issued final new safety regulations for hazardous liquid pipelines, including a requirement that all hazardous liquid pipelines have a system for detecting leaks and addressing affected pipelines following extreme weather events or natural disasters. However, this rule was subsequently withdrawn by PHMSA on January 24, 2017; the future disposition of these potential new requirements remains uncertain.

State Regulation. Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Commitments and Contingencies

The Company’s activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement policies included, and claims for damages to property, employees, other persons, and the environment resulting from the Company’s operations could have on its activities. See Note 14 in the Footnotes to the Financial Statements for additional information.

Available Information

We make available free of charge on our website (www.callon.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the SEC.

We also make available within the "About Callon" section of our website our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation, Strategic Planning and Reserve, and Nominating and Corporate Governance Committee Charters, which have been approved by our Board of Directors. We will make timely disclosure on our website of any change to, or waiver from, the Code of Business Conduct and Ethics for our principal executive and senior financial officers. A copy of our Code of Business Conduct and Ethics is also available, free of charge by writing us at: General Counsel, Callon Petroleum Company, 1401 Enclave Parkway, Suite 600, Houston, TX 77077.

ITEM 1A. Risk Factors

Risk Factors

Risks Related to the Oil & Natural Gas Industry

Oil and natural gas prices are volatile, and substantial or extended declines in prices may adversely affect our results of operations and financial condition. Our success is highly dependent on prices for oil and natural gas, which have been extremely volatile in recent years. Approximately 75% - 80% of our anticipated 2019 production is oil, on a BOE basis. Extended periods of low prices for oil or natural gas will have a material adverse effect on us. The prices of oil and natural gas depend on factors we cannot control such as macro-economic conditions, levels of production, demand for oil and natural gas, relative price and availability of alternative forms of energy, actions by OPEC and other countries, legislative and regulatory actions, technology developments impacting energy consumption and energy supply, and weather. Prices of oil and natural gas will affect the following aspects of our business:

- our revenues, cash flows, earnings and returns;
- the amount of oil and natural gas that we are economically able to produce;
- our ability to attract capital to finance our operations and the cost of the capital;
- the amount we are allowed to borrow under our Credit Facility;
- the profit or loss we incur in exploring for and developing our reserves; and
- the value of our oil and natural gas properties.

These factors and the volatility of the energy markets, which we expect will continue, make it extremely difficult to predict future oil, natural gas and NGLs price movements with any certainty. During the five years ended December 31, 2018, NYMEX WTI oil futures contract prices ranged from a high of $107.26 per barrel on June 20, 2014 to a low of $26.21 per barrel on February 11, 2016, and NYMEX Henry Hub gas futures prices ranged from a high of $6.15 per MMBtu on February 19, 2014 to a low of $1.64 per MMBtu on March 3, 2016. As of December 31, 2018, NYMEX WTI oil futures contract prices and NYMEX Henry Hub gas futures prices were $45.41 per barrel and $2.94 per MMBtu, respectively.

Although oil and natural gas prices have increased significantly since 2016, a buildup in inventories, lower global demand, or other factors could cause commodity prices to weaken, which could negatively affect our cash flows and results of operations. Under such conditions, we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. Lower commodity prices may also reduce the amount of oil and natural gas that we can produce economically.

If commodity prices decrease from current levels, a significant portion of our development projects could become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. In addition, fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas.

Any substantial and extended decline in the price of oil or natural gas could have an adverse effect on our borrowing capacity, our ability to obtain additional capital, and our revenues, profitability and cash flows.

If oil and natural gas prices remain depressed for extended periods of time, we may be required to make significant downward adjustments to the carrying value of our oil and natural gas properties. Under the full cost method, which we use to account for our oil and natural gas properties, the net capitalized costs of our oil and natural gas properties may not exceed the present value, discounted at 10%, of future net cash flows from estimated net proved reserves, using the preceding 12-months' average oil and natural gas prices, plus the lower of cost or fair market value of our unproved properties. If net capitalized costs of our oil and natural gas properties exceed this "ceiling test" limit, we must charge the amount of the excess to earnings. This type of charge will not affect our cash flows, but will reduce the book value of our stockholders' equity. We review the carrying value of our properties quarterly and once incurred, a write-down of oil and natural gas properties is not reversible at a later date, even if prices increase. See Note 2 in the Footnotes to the Financial Statements as well as the Supplemental Information on Oil and Natural Gas Operations for additional information.

For the period ended December 31, 2018, we did not recognize a write-down of oil and natural gas properties as a result of the ceiling test limitation. The ceiling test calculation as of December 31, 2018 was calculated using the average annual realized prices used in determining the estimated future net cash flows from proved reserves of $58.40 per barrel of oil and $3.64 per Mcf of natural gas. Oil prices continue to fluctuate and we may experience ceiling test write-downs in the future. Any future ceiling test cushion, and the risk we may incur write-downs or impairments, will be subject to fluctuation as a result of acquisition or divestiture activity.

Our estimated reserves are based on interpretations and assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. This 2018 Annual Report on Form 10-K contains estimates of our proved oil and natural gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir and is therefore inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from the estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. Additionally, estimates of reserves and future cash flows may be subject to material downward or upward revisions, based on production history, development drilling and exploration activities and prices of oil and natural gas.

You should not assume that any present value of future net cash flows from our estimated net proved reserves contained in this 2018 Annual Report on Form 10-K represents the market value of our oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2018 on average 12-month prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations or taxes. At December 31, 2018, approximately 29% of the discounted present value of our estimated net proved reserves consisted of PUDs. PUDs represented 46% of total proved reserves by volume. Recovery of PUDs generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these PUDs and the actual costs, development schedule, and results associated with these properties may not be as estimated. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and gas industry in general.

Unless we replace our oil and gas reserves, our reserves and production will decline. Our future oil and gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our production, revenues, reserve quantities and cash flows will decline. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. We may not be successful in finding, developing or acquiring additional reserves, and our efforts may not be economic. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable.

Competitive industry conditions may negatively affect our ability to conduct operations. We compete with numerous other companies in virtually all facets of our business. Our competitors in development, exploration, acquisitions and production include major integrated oil and gas companies and smaller independents as well as numerous financial buyers. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit. We also compete for the materials, equipment, personnel and services that are necessary for the exploration, development and operation of our properties. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development. Factors that affect our ability to compete in the marketplace include our:

- access to the capital necessary to drill wells and acquire properties;
- ability to acquire and analyze seismic, geological and other information relating to a property;
- ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- ability to procure materials, equipment, personnel and services required to explore, develop and operate our properties, including the ability to procure fracture stimulation services on wells drilled; and
- ability to access pipelines, and the location of facilities used to produce and transport oil and natural gas production.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget. From time to time, our industry experiences a shortage of drilling rigs, equipment, supplies, water or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews and other experienced personnel rise as the level of activity increases. Increasing levels of exploration and production may increase the demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. The unavailability or high cost of drilling rigs, pressure pumping equipment, supplies, water or qualified personnel can materially and adversely affect our operations and profitability.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in a single geographic region. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area. All of our producing properties are geographically concentrated in the Permian Basin of West Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services, or market limitations or interruption of the processing or transportation of oil, natural gas or natural gas liquids. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. 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. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

We may be unable to integrate successfully the operations of recent acquisitions with our operations, and we may not realize all the anticipated benefits of these acquisitions. Our business has, and may in the future include, acquisitions that include undeveloped acreage. We can offer no assurance that we will achieve the desired profitability from our recent acquisitions or from any acquisitions we may complete in the future. In addition, failure to assimilate recent and future acquisitions successfully could adversely affect our financial condition and results of operations. Our acquisitions may involve numerous risks, including:

- operating a larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new geographic area;
- risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- loss of significant key employees from the acquired business;
- inability to obtain satisfactory title to the assets we acquire;
- a decrease in our liquidity if we use a portion of our available cash to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- diversion of management’s attention from other business concerns;
- failure to realize expected profitability or growth;
- failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisition and current operations, which in turn, could negatively impact our results of operations.

We may fail to fully identify problems with any properties we acquire, and as such, assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities. We are actively seeking to acquire additional acreage in Texas or other regions in the future. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, adequacy of title, operating and capital costs and potential environmental and other liabilities. Although we conduct a review which we believe is consistent with industry practices, we can give no assurance that we have identified or will identify all existing or potential problems associated with such properties or that we will be able to mitigate any problems we do identify. Such assessments are inexact and their accuracy is inherently uncertain. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface, title and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

Restrictions on our ability to obtain, recycle and dispose of water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner. Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to secure water from local land owners and other third party sources for use in our operations. If drought conditions were to occur or demand for water were to outpace supply, our ability to obtain water could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly. Along with the risks of other extreme weather events, drought risk, in particular, is likely increased by climate change. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows. In addition, significant amounts of water are produced in our operations. Inadequate access to or availability of water recycling or water disposal facilities could adversely affect our production volumes or significantly increase the cost of our operations.

Factors beyond our control affect our ability to market production and our financial results. The ability to market oil and natural gas from our wells depends upon numerous factors beyond our control. These factors could negatively affect our ability to market all of the oil or natural gas we produce. In addition, we may be unable to obtain favorable prices for the oil and natural gas we produce. These factors include:

- the extent of domestic production and imports/exports of oil and natural gas;
- federal regulations authorizing exports of liquefied natural gas ("LNG"), the development of new LNG export facilities under construction in the U.S. Gulf Coast region, and the first LNG exports from such facilities;
- the construction of new pipelines capable of exporting U.S. natural gas to Mexico and Permian Basin oil production to the Gulf Coast;
- the proximity of hydrocarbon production to pipelines;
- the availability of gas processing, pipeline, and/or refining capacity;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- state and federal regulation of oil and natural gas marketing; and
- federal regulation of natural gas sold or transported in interstate commerce.

In particular, in areas with increasing non-conventional shale drilling activity, pipeline, rail or other transportation capacity may be limited and it may be necessary for new interstate and intrastate pipelines and gathering systems to be built.

The marketability of our production is dependent upon transportation facilities and services owned and operated by third parties, and the unavailability of these facilities or services would have a material adverse effect on our revenue. Our ability to market our production depends on the availability and capacity of gas processing facilities and pipeline and other transportation operations, including trucking services, owned and operated by third parties. These facilities and services may be temporarily unavailable to us due to market conditions, physical or mechanical disruption, weather, lack of contracted capacity or other reasons. In addition, in certain newer development areas, processing and transportation facilities and services may not be sufficient to accommodate potential production. Our failure to obtain access to processing and transportation facilities and services on acceptable terms could materially harm our business. We may be required to shut in wells for lack of a market or because of inadequate or unavailable processing or transportation 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. If we were required to shut in our production for long periods of time due to lack of transportation capacity, it would have a material adverse effect on our business, financial condition, results of operations and cash flows.

We have entered into firm transportation contracts that require us to pay fixed sums of money regardless of quantities actually shipped. If we are unable to deliver the necessary quantities of production, our results of operations, financial position, and liquidity could be adversely affected. We have entered into firm transportation agreements for a portion of our production in such areas in order to assure our ability, and that of our purchasers, to successfully market our production. We may also enter into firm transportation arrangements for additional production in the future. These firm transportation agreements may be more costly than interruptible or short-term transportation agreements. Additionally, these agreements obligate us to pay fees on minimum volumes regardless of actual throughput. If we have insufficient production to meet the minimum volumes, the requirements to pay for quantities not delivered could have an impact on our results of operations, financial position, and liquidity.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns. Exploration, development, drilling and production activities are subject to many risks. We may invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that any leasehold acreage acquired will be profitably developed, that new wells drilled will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, including wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Wells may have production decline rates that are greater than anticipated. Future drilling and completion efforts may impact production from existing wells, and parent-child effects may impact future well productivity as a result of timing, spacing proximity or other factors.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. We may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including among others:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- lack of proximity to and shortage of capacity of transportation facilities;
- equipment failures or accidents and shortages or delays in the availability of drilling rigs, equipment, personnel and services; and
- compliance with governmental requirements.

Failure to conduct our oil and gas operations in a profitable manner may result in write-downs of our proved reserves quantities, impairment of our oil and gas properties, and a write-down in the carrying value of our unproved properties, and over time may adversely affect our growth, revenues and cash flows.

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could prevent them from being drilled or delay their drilling. Our management team has identified drilling locations as an estimation of our future development activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these identified drilling locations depends on a number of uncertainties, including among others:

- oil and natural gas prices;
- the availability and cost of capital;
- availability and cost of drilling, completion and production services and equipment;
- drilling results and production decline rates;
- lease expirations;
- gathering, marketing and transportation constraints; and
- regulatory approvals.

Because of these uncertain factors, we do not know if the identified drilling locations will ever be drilled or if we will be able to produce oil or natural gas from these drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the identified locations are located, the leases for such acreage will expire. Therefore, our actual drilling activities may materially differ from those presently identified.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Approximately 46% of our total estimated proved reserves as of December 31, 2018, were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

The results of our planned development programs in new or emerging shale development areas and formations may be subject to more uncertainties than programs in more established areas and formations, and may not meet our expectations for reserves or production. The results of our horizontal drilling efforts in emerging areas and formations of the Permian Basin are generally more uncertain than drilling results in areas that are more developed and have more established production from horizontal formations such as the Wolfcamp, Spraberry and Bone Spring horizons. Because emerging areas and associated target formations have limited or no production history, we are less able to rely on past drilling results in those areas as a basis to predict our future drilling results. In addition, horizontal wells drilled in shale formations, as distinguished from vertical wells, utilize multilateral wells and stacked laterals, all of which are subject to well spacing, density and proration requirements of the Texas Railroad Commission, which requirements could adversely impact our ability to maximize the efficiency of our horizontal wells related to reservoir drainage over time. Further, access to adequate gathering systems or pipeline takeaway capacity and the availability of drilling rigs and other services may be more challenging in new or emerging areas. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, access to gathering systems and takeaway capacity or otherwise, and/or natural gas and oil prices decline, our investment in these areas may not be as economic as we anticipate, we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our ability to conduct business. There are many operating hazards in exploring for and producing oil and natural gas, including:

- our drilling operations may encounter unexpected formations or pressures, which could cause damage to equipment or personal injury;
- we may experience equipment failures which curtail or stop production;
- we could experience blowouts or other damages to the productive formations that may require a well to be re-drilled or other corrective action to be taken; and
- storms and other extreme weather conditions could cause damages to our production facilities or wells.

Because of these or other events, we could experience environmental hazards, including release of oil and natural gas from spills, natural gas-leaks, accidental leakage of toxic or hazardous materials, such as petroleum liquids, drilling fluids or fracturing fluids, including chemical additives, underground migration, and ruptures.

If we experience any of these problems, it could affect wells, gathering systems and processing facilities, which could adversely affect our ability to conduct operations. We could also incur substantial losses in excess of our insurance coverage as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

We cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable to cover our possible losses from operating hazards. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and results of operations.

Multi-well pad drilling may result in volatility in our operating results. We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause volatility in our quarterly operating results.

The loss of key personnel could adversely affect our ability to operate. We depend, and will continue to depend in the foreseeable future, on the services of our senior officers and other key employees, as well as other third-party consultants with extensive experience and expertise in evaluating and analyzing drilling prospects and producing oil and natural gas and maximizing production from oil and natural gas properties. Our ability to retain our senior officers, other key employees and our third party consultants, none of whom are subject to employment agreements, is important to our future success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business.

We may not be able to keep pace with technological developments in our industry. The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

Our business could be negatively affected by security threats. A cyberattack or similar incident could occur and result in information theft, data corruption, operational disruption, damage to our reputation and/or financial loss. The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, manage operations, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Our technologies, systems, networks, seismic data, reserves information or other proprietary information, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or could otherwise lead to the disruption of our business operations or other operational disruptions in our exploration or production operations. Cyberattacks are becoming more sophisticated and certain cyber incidents, such as surveillance, may remain undetected for an extended period and could lead to disruptions in critical systems or the unauthorized release of confidential or otherwise protected information. These events could lead to financial losses from remedial actions, loss of business, disruption of operations, damage to our reputation or potential liability. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyberattack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. Cyber incidents have increased, and the U.S. government has issued warnings indicating that energy assets may be specific targets of cybersecurity threats. Our systems and insurance coverage for protecting against cybersecurity risks may not be sufficient. Further, as cyberattacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyberattacks.

Risks Related to Financial Position

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing on satisfactory terms or at all. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Historically, we have funded our capital expenditures through a combination of cash flows from operations, borrowings from financial institutions, the sale of public debt and equity securities and asset dispositions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, participation of non-operating working interest owners, the cost and availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

If the borrowing base under our Credit Facility or our revenues decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or cash available under our Credit Facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our drilling locations, which in turn could lead to a possible expiration of our leases and a decline in our estimated net proved reserves, and could adversely affect our business, financial condition and results of operations.

Restrictive covenants in our Credit Facility and the indenture governing our 6.125% senior unsecured notes due 2024 (“6.125% Senior Notes”) and 6.375% senior unsecured notes due 2026 (“6.375% Senior Notes”) may limit our ability to respond to changes in market conditions or pursue business opportunities. Our Credit Facility and the indenture governing our 6.125% Senior Notes and 6.375% Senior Notes contain restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;
- make investments;
- merge or consolidate with another entity;
- pay dividends or make certain other payments;

- hedge future production or interest rates;
- create liens that secure indebtedness;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

As a result of these covenants, we are limited in the manner in which we conduct our business and we may be unable to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

In addition, our Credit Facility requires us to maintain certain financial ratios and to make certain required payments of principal, premium, if any, and interest. If we fail to comply with these provisions or other financial and operating covenants in the Credit Facility and the indenture governing the 6.125% Senior Notes and 6.375% Senior Notes, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;
- the lenders under our Credit Facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets; and
- we could be forced into bankruptcy or liquidation.

Our borrowings under our Credit Facility expose us to interest rate risk. Our earnings are exposed to interest rate risk associated with borrowings under our Credit Facility, which bear interest at a rate elected by us that is based on the prime, LIBOR or federal funds rate plus margins ranging from 1.25% to 2.25% depending on the interest rate used and the amount of the loan outstanding in relation to the borrowing base.

The borrowing base under our Credit Facility may be reduced below the amount of borrowings outstanding under such facilities. The borrowing base under our Credit Facility is currently $1.1 billion, with elected commitments of $850 million. In the future, we may not be able to access adequate funding under our Credit Facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations. In addition, we cannot borrow amounts above the elected commitments, even if the borrowing base is greater, without new commitments being obtained from the lenders for such incremental amounts above the elected commitments. Our borrowing base is subject to redeterminations semi-annually, and our next scheduled borrowing base redetermination is expected to occur on or about May 2019. If our borrowing base were to be reduced, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness. In addition, in the event the amount outstanding under our Credit Facility exceeds the elected commitments, we must repay such amounts immediately in cash. In the event the amount outstanding under our Credit Facility exceeds the redetermined borrowing base, we are required to either (i) grant liens on additional oil and gas properties (not previously evaluated in determining such borrowing base) with a value equal to or greater than such excess, (ii) repay such excess borrowings over six monthly installments, or (iii) elect a combination of options in clauses (i) and (ii). We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, an event of default would occur under our Credit Facility.

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 certain financial, economic, competitive 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. Our Credit Facility currently restricts 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.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations, and business prospects. As of December 31, 2018, we had $600 million outstanding of 6.125% Senior Notes due 2024, $400 million outstanding of our 6.375% Senior Notes due 2026, and $200 million outstanding under our Credit Facility, which had an additional $632.3 million available for borrowings based on the existing level of commitments. Our amount of indebtedness could affect our operations in several ways, including the following:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities;
- limit management's discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- increase our vulnerability to downturns and adverse developments in our business and the economy;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;

- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings;
- make us vulnerable to increases in interest rates as our indebtedness under our Credit Facility may vary with prevailing interest rates;
- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness or less restrictive terms governing their indebtedness; and
- make it more difficult for us to satisfy our obligations under the 6.125% Senior Notes, 6.375% Senior Notes, or other debt and increase the risk that we may default on our debt obligations.

We cannot assure you that we will be able to maintain or improve our leverage position. An element of our business strategy involves maintaining a disciplined approach to financial management. However, we are also seeking to acquire, exploit and develop additional reserves that may require the incurrence of additional indebtedness. Although we will seek to maintain or improve our leverage position, our ability to maintain or reduce our level of indebtedness depends on a variety of factors, including future performance and our future debt financing needs. General economic conditions, oil and natural gas prices and financial, business and other factors will also affect our ability to maintain or improve our leverage position. Many of these factors are beyond our control.

We may not be insured against all of the risks to which our business is exposed from ongoing or legacy operations. In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We cannot assure you that our insurance will be adequate to cover all losses or liabilities related to our current or legacy operations. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. No assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable and may elect none or minimal insurance coverage. The occurrence of a significant event or claim, not fully insured or indemnified against, could have a material adverse effect on our financial condition and operations.

Our hedging program may limit potential gains from increases in commodity prices or may result in losses or may be inadequate to protect us against continuing and prolonged declines in commodity prices. We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. Our hedges at December 31, 2018 are in the form of collars, put and call options, basis swaps, and other structures placed with the commodity trading branches of certain national banking institutions and with certain other commodity trading groups. These hedging arrangements may limit the benefit we could receive from increases in the market or spot prices for oil and natural gas. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in oil and natural gas prices. These hedges may be inadequate to protect us from continuing and prolonged declines in oil and natural gas prices. To the extent that oil and natural gas prices remain at current levels or decline further, we will not be able to hedge future production at the same pricing level as our current hedges and our results of operations and financial condition would be negatively impacted.

We may not have production to offset hedges. Part of our business strategy is to reduce our exposure to the volatility of oil and natural gas prices by hedging a portion of our production. In a typical hedge transaction, we will have the right to receive from the other parties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the other parties this difference multiplied by the quantity hedged regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of physical production.

Our hedging transactions expose us to counterparty credit risk. Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty’s liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract. During periods of falling commodity prices, our hedging transactions expose us to risk of financial loss if our counterparty to a derivatives transaction fails to perform its obligations under a derivatives transaction. We are unable to predict sudden changes in a counterparty’s creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results. Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates, advances to joint interest parties and joint interest receivables. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. The largest purchaser of our oil and natural gas accounted for approximately 28% of our total oil and natural gas revenues for the year ended December 31, 2018. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Our ability to use our existing net operating loss carryforwards or other tax attributes could be limited. At December 31, 2018, we had approximately $721 million of federal NOL carryforwards available to offset against future taxable income. Of this NOL carryforward balance, $663 million was generated prior to the effective date of new limitations on utilization of NOLs imposed by the Tax Cuts and Jobs Act of 2017 (the “Tax Act”) and are allowable as a deduction against 100 percent of taxable income in future years but will start to expire in the tax year 2021. Utilization of any NOL depends on many factors, including our ability to generate future taxable income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended (“Section 382”), generally imposes an annual limitation on the amount of NOLs that may be used to offset taxable income when a corporation has undergone an “ownership change” (as determined under Section 382). Future ownership changes or future regulatory changes could limit our ability to utilize our NOLs. To the extent we are not able to offset our future income with our NOLs, this could adversely affect our operating results and cash flows once we attain profitability.

We have no plans to pay cash dividends on our common stock in the foreseeable future. The terms of our Credit Facility contain limitations that impact our ability to pay dividends and make other distributions. In addition, any future determination as to the declaration and payment of cash dividends will be at the discretion of our Board of Directors and will depend upon our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors deemed relevant by our Board of Directors.

The availability of shares for sale in the future could reduce the market price of our common stock. In the future, we may issue securities to raise cash for acquisitions. We may also acquire interests in other companies by using a combination of cash and our common stock or only our common stock. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock. In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

Legal and Regulatory Risks

We are subject to stringent and complex federal, state and local laws and regulations which require compliance that could result in substantial costs, delays or penalties. Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. For a discussion of the material regulations applicable to us, see “Regulations.” These laws and regulations may:

- require that we acquire permits before commencing drilling;
- regulate the spacing of wells and unitization and pooling of properties;
- impose limitations on production or operational, emissions control and other conditions on our activities;
- restrict the substances that can be released into the environment or used in connection with drilling and production activities or restrict the disposal of waste from our operations;
- limit or prohibit drilling activities on protected areas such as wetlands, wilderness or other protected areas;
- impose penalties and other sanctions for accidental and/or unpermitted spills or releases from our operations; and
- require measures to remediate or mitigate pollution and environmental impacts from current and former operations, such as cleaning up spills or dismantling abandoned production facilities.

Significant expenditures may be required to comply with governmental laws and regulations applicable to us. In addition, failure to comply with these laws and regulations may result in the assessment of penalties, permit revocations, requirements for additional pollution controls or injunctions limiting or prohibiting operations.

The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal, state and local agencies frequently revise environmental laws and regulations, and such changes could result in increased costs for environmental compliance, such as emissions control, waste handling, permitting, or cleanup for the oil and natural gas industry and could have a significant impact on our operating costs. In general, the oil and natural gas industry recently has been the subject of increased legislative and regulatory attention with respect to environmental matters. Even if regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental legislation and regulations may continue in the long-term.

Further, under these laws and regulations, we could be liable for costs of investigation, removal and remediation, damages to and loss of use of natural resources, loss of profits or impairment of earning capacity, property damages, costs of increased public services, as well as administrative, civil and criminal fines and penalties, and injunctive relief. Certain environmental statutes, including the RCRA, CERCLA, OPA and analogous state laws and regulations, impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances or other waste products have been disposed of or otherwise released. We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, GHGs and hydraulic fracturing. Under the common law, we could be liable for injuries to people and property. We maintain limited insurance coverage for sudden and accidental environmental damages. We do not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Also, we do not believe that insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or we may be required to cease production from properties in the event of environmental incidents.

Federal legislation and state and local legislative and regulatory initiatives relating to hydraulic fracturing and water disposal wells could result in increased costs and additional operating restrictions or delays. Hydraulic fracturing is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production and is typically regulated by state oil and gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of “underground injection” and to require federal permitting and regulatory control of hydraulic fracturing but has not passed. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as “Class II” Underground Injection Control wells under the Safe Drinking Water Act. The EPA has also published air emission standards for certain equipment, processes and activities across the oil and natural gas sector, although the EPA is currently in the process of revising its approach to regulation of methane emission.

In some areas of Texas, there has been concern that certain formations into which disposal wells are injecting produced waters could become over-pressured after many years of injection, and the governing Texas regulatory agency is reviewing the data to determine whether any action is necessary to address this issue. If the Texas state agency were to decline to issue permits for, or limit the volumes of, new injection wells into the formations currently utilized by us, we may be required to seek alternative methods of disposing of produced waters, including injecting into deeper formations, which could increase our costs.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, impose additional requirements on hydraulic fracturing activities or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, Texas law requires the chemical components used in the hydraulic fracturing process, as well as the volume of water used, must be disclosed to the RRC and the public. Furthermore, the RRC has issued the “well integrity rule” which includes new testing and reporting requirements, such as (i) the requirement to submit to the RRC cementing reports after well completion or cessation of drilling, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. Additionally, the RRC has adopted a rule requiring applicants for certain new water disposal wells to conduct seismic activity searches using the U.S. Geological Survey to determine the potential for earthquakes within a circular area of 100 square miles. The rule also clarifies the RRC’s authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal wells. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general and/or hydraulic fracturing in particular.

In December 2016, the EPA released its final report "Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States." This report concludes that hydraulic fracturing can impact drinking water resources in certain circumstances but also noted that certain date gaps and uncertainties limited EPA's assessment.   This study could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, water usage and the potential for impacts to surface water, groundwater and the environment generally, and a number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. If new laws or regulations that significantly restrict hydraulic fracturing or water disposal wells are adopted, such laws could make it more difficult or costly for us to drill for and produce oil and natural gas as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, permitting delays and potential increases in costs. These changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Climate change legislation or regulations restricting emissions of greenhouse gases, changes in the availability of financing for fossil fuel companies, and physical effects from climate change could adversely impact our operating costs and demand for the oil and natural gas we produce. In recent years, federal, state and local governments have taken steps to reduce emissions of GHGs. The EPA has finalized a series of GHG monitoring, reporting and emissions control rules, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Several states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. While we are subject to certain federal GHG monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives. For a description of existing and proposed GHG rules and regulations, see "Regulations."

In December 2015, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change resulted in 195 countries, including the United States, coming together to develop the so-called "Paris Agreement," which calls for the parties to undertake "ambitious efforts" to limit the average global temperature. The Agreement went into effect on November 4, 2016, and establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions. While the United States announced that it would withdraw from the Paris Agreement on June 1, 2017, given the requirements of the withdrawal process the earliest possible exit would be November 2020. Certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. A number of states have begun taking actions to control and/or reduce emissions of GHGs. Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries 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 GHG emissions could have an adverse effect on our business, financial condition and results of operations.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of, and value of our products and reserves. As our operations also emit GHGs directly, current and future laws or regulations limiting such emissions could increase our own costs. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business.

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. Furthermore, some parties have initiated public nuisance claims under federal or state common law against certain companies involved in the production of oil and natural gas. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. Although our business in not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Finally, most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of droughts, storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves.

Current or proposed financial legislation and rulemaking could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) establishes federal oversight and regulation of over-the-counter derivatives and requires the U.S. Commodity Futures Trading Commission (the “CFTC”) and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over-the-counter market.

Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized. In one of the CFTC’s rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC has proposed but not yet approved position limits for certain futures and options contracts in various commodities and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions). Similarly, the CFTC has proposed but not yet finalized a rule regarding the capital that a swap dealer or major swap participant is required to post with respect to its swap business. The CFTC issued a final rule on margin requirements for uncleared swap transactions in January 2016, which it amended in November 2018. The final rule as amended includes an exemption for certain commercial end-users that enter into uncleared swaps in order to hedge bona fide commercial risks affecting their business. In addition, the CFTC has issued a final rule authorizing an exception from the requirement to use cleared exchanges (rather than hedging over-the-counter) for commercial end-users who use swaps to hedge their commercial risks. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business.

While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or capital requirements, depending on our ability to satisfy the CFTC's requirements for the various exemptions available for a commercial end-user using swaps to hedge or mitigate its commercial risks, these rules and regulations may provide beneficial exemptions or may require us to comply with position limits and other limitations with respect to our financial derivative activities. When a final rule on capital requirements is issued, the Dodd-Frank Act may require our current counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which could increase the cost to us of entering into such derivatives. The Dodd-Frank Act may also require our current counterparties to financial derivative transactions to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and may cause some entities to cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets which would reduce the ability of commercial end-users like us to hedge or mitigate their exposure to commodity price volatility. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of future swaps relative to the terms of our existing financial derivative contracts, and reduce the availability of derivatives to protect against commercial risks we encounter.

In addition, federal banking regulators have adopted new capital requirements for certain regulated financial institutions in connection with the Basel III Accord. The Federal Reserve Board also issued proposed regulations on September 30, 2016, proposing to impose higher risk-weighted capital requirements on financial institutions active in physical commodities, such as oil and natural gas. If and when these proposed regulations are fully implemented, financial institutions subject to these higher capital requirements may require that we provide cash or other collateral with respect to our obligations under the financial derivatives and other contracts in order to reduce the amount of capital such financial institutions may have to maintain. Alternatively, financial institutions subject to these capital requirements may require premiums to enter into derivatives and other physical commodity transactions to compensate for the additional capital costs for these transactions. Rules implementing the Basel III Accord and higher risk-weighted capital requirements could materially reduce our liquidity and increase the cost of derivative contracts and other physical commodity contracts (including through requirements to post collateral which could adversely affect our available capital for other commercial operations purposes).

If we reduce our use of derivative contracts as a result of any of the foregoing new requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, natural gas and natural gas liquids prices, which some legislators attributed to speculative trading in derivatives and commodity instruments. Our revenues could t be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Tax laws and regulations may change over time, and the recently passed comprehensive tax reform bill could adversely affect our business and financial condition. On December 22, 2017, the President signed into law Public

Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Act that significantly reforms the Internal Revenue Code of 1986, as amended (the “Code”). The Tax Act, among other things, (i) permanently reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) eliminates the deduction for certain domestic production activities, (iv) imposes new limitations on the utilization of net operating losses, and (v) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. The Tax Act is complex and far-reaching and we cannot predict with certainty the resulting impact its enactment has on us. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued and any such changes in interpretations or assumptions could adversely affect our business and financial condition. See Note 12 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

In addition, from time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including (i) the elimination of the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties and (iii) an extension of the amortization period for certain geological and geophysical expenditures. While these specific changes are not included in the Tax Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could adversely affect our business and financial condition.

Provisions of our charter documents and Delaware law may inhibit a takeover, which could limit the price investors might be willing to pay in the future for our common stock. Provisions in our certificate of incorporation and bylaws may have the effect of delaying or preventing an acquisition of the Company or a merger in which we are not the surviving company and may otherwise prevent or slow changes in our board of directors and management. In addition, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the Delaware General Corporation Law. These provisions could discourage an acquisition of the Company or other change in control transactions and thereby negatively affect the price that investors might be willing to pay in the future for our common stock.

We may be subject to the actions of activist shareholders. We have been the subject of an activist shareholder in the past. Responding to shareholder activism can be costly and time-consuming, disrupt our operations and divert the attention of management and our employees from executing our business plan. Activist campaigns can create perceived uncertainties as to our future direction, strategy or leadership and may result in the loss of potential business opportunities, harm our ability to attract new investors, customers and joint venture partners and cause our stock price to experience periods of volatility or stagnation. Moreover, if individuals are elected to our board of directors with a specific agenda, our ability to effectively and timely implement our current initiatives, retain and attract experienced executives and employees and execute on our long-term strategy may be adversely affected.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 3. Legal Proceedings

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. We believe that the ultimate resolution of any such actions will not have a material effect on our financial position or results of operations.

ITEM 4. Mine Safety Disclosures

Not applicable.

PART II.
ITEM 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock trades on the New York Stock Exchange under the symbol "CPE".

Holders

As of February 22, 2019 the Company had approximately 2,630 common stockholders of record.

Dividends

We have not paid any cash dividends on our common stock to date and presently do not expect to declare or pay any cash dividends on our common stock in the foreseeable future as we intend to reinvest our cash flows and earnings into our business. The declaration and payment of dividends is subject to the discretion of our Board of Directors and to certain limitations imposed under Delaware corporate law and the agreements governing our debt obligations. The timing, amount and form of dividends, if any, will depend on, among other things, our results of operations, financial condition, cash requirements and other factors deemed relevant by our Board of Directors. In addition, certain of our debt facilities contain restrictions on the payment of dividends to the holders of our common stock.

Holders of our 10% Series A Cumulative Preferred Stock are entitled to a cumulative dividend whether or not declared, of $5.00 per annum, payable quarterly, equivalent to 10.0% of the liquidation preference of $50.00 per share. Unless the full amount of the dividends for the 10% Series A Cumulative Preferred Stock is paid in full, we cannot declare or pay any dividend on our common stock.

Equity Compensation Plan Information

The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2018 (securities amounts are presented in thousands).

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights		Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders	—	$	—	9,807
Equity compensation plans not approved by security holders	—	$	—	—
Total	—	$	—	9,807

For additional information regarding the Company's share-based compensation expense, see Note 10 in the Footnotes to the Financial Statements.

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Performance Graph

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the performance of the Company's common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

The graph below compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the Standard & Poor's 500 Index ("S&P 500 Index") and Dow Jones US Select Oil & Gas Exploration and Production Index ("DJ US Select O&G E&P Index") from December 31, 2013, through December 31, 2018.

The stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing

Comparison of Five Year Cumulative Total Return
Assumes Initial Investment of $100
December 2018

	For the Year Ended December 31,					
Company/Market/Peer Group	2013	2014	2015	2016	2017	2018
Callon Petroleum Company	$100.00	$83.46	$127.72	$235.38	$186.06	$99.39
S&P 500 Index - Total Returns	100.00	113.69	115.26	129.05	157.22	150.32
DJ US Select O&G E&P	100.00	88.06	66.49	83.68	84.26	68.25

ITEM 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, selected financial information about the Company. The financial information for each of the five years in the period ended December 31, 2018 has been derived from our audited Consolidated Financial Statements for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto. The following information is not necessarily indicative of our future results (dollars in thousands, except per share amounts).

	For the Year Ended December 31,				
	2018	2017	2016	2015	2014
Statement of Operations Data					
Operating revenues					
Oil and natural gas sales	$587,624	$366,474	$200,851	$137,512	$151,862
Operating expenses					
Total operating expenses	$328,094	$225,028	$248,328	$346,622	$113,592
Income (loss) from operations	259,530	141,446	(47,477)	(209,110)	38,270
Net income (loss) [a]	300,360	120,424	(91,813)	(240,139)	37,766
Income (loss) per share ("EPS")					
Basic	$1.35	$0.56	$(0.78)	$(3.77)	$0.67
Diluted	$1.35	$0.56	$(0.78)	$(3.77)	$0.65
Weighted average shares outstanding for Basic EPS	216,941	201,526	126,258	65,708	44,848
Weighted average shares outstanding for Diluted EPS	217,596	202,102	126,258	65,708	45,961
Statement of Cash Flows Data					
Net cash provided by operating activities	$467,654	$229,891	$120,774	$89,319	$94,387
Net cash used in investing activities	(1,324,057)	(1,072,532)	(866,287)	(259,160)	(452,501)
Net cash provided by financing activities	844,459	217,643	1,397,282	170,097	356,070
Balance Sheet Data					
Total oil and natural gas properties	$3,718,858	$2,513,491	$1,475,401	$711,386	$742,155
Total assets	3,979,173	2,693,296	2,267,587	788,594	863,346
Long-term debt [b]	1,189,473	620,196	390,219	328,565	321,576
Stockholders' equity	2,445,208	1,855,966	1,733,402	362,758	433,735
Proved Reserves Data					
Total oil (MBbls)	180,097	107,072	71,145	43,348	25,733
Total natural gas (MMcf)	350,466	179,410	122,611	65,537	42,548
Total (MBOE)	238,508	136,974	91,580	54,271	32,824
Standardized measure [c]	$2,941,293	$1,556,682	$809,832	$570,890	$579,542

(a) Net loss for 2015 included the recognition of a write-down of oil and natural gas properties of $208,435 as a result of the ceiling test limitation and $108,843 of income tax expense related to the recognition of a valuation allowance. Net loss for 2016 included the recognition of a write-down of oil and natural gas properties of $95,788 as a result of the ceiling test limitation. See the Supplemental Information on Oil and Gas Operations for more discussion.

(b) See Note 6 in the Footnotes to the Financial Statements for additional information.

(c) Standardized measure is the future net cash flows related to estimated proved oil and natural gas reserves together with changes therein, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet. Prices are based on either the preceding 12-months' average price, based on closing prices on the first day of each month, or prices defined by existing contractual arrangements. Future production and development costs are based on current estimates with no escalations. Estimated future cash flows have been discounted to their present values based on a 10% discount rate. See the Supplemental Information on Oil and Gas Operations for more discussion.

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ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following management's discussion and analysis describes the principal factors affecting the Company's results of operations, liquidity, capital resources and contractual cash obligations. This discussion should be read in conjunction with the accompanying audited consolidated financial statements, information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results, which are included in various parts of this filing. Our website address is www.callon.com. All of our filings with the SEC are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this 2018 Annual Report on Form 10-K.

We are an independent oil and natural gas company incorporated in the State of Delaware in 1994, but our roots go back nearly 70 years to our Company's establishment in 1950. We are focused on the acquisition, development, exploration and exploitation of unconventional, onshore, oil and natural gas reserves in the Permian Basin. The Permian Basin is located in West Texas and southeastern New Mexico and is comprised of three primary sub-basins: the Midland Basin, the Delaware Basin, and the Central Basin Platform. Since our entry into the Permian Basin in late 2009, we have historically been focused on the Midland Basin and more recently entered the Delaware Basin through an acquisition completed in February 2017. We further expanded our presence in the Delaware Basin through our acquisitions in 2018. Our operating culture is centered on responsible development of hydrocarbon resources, safety and the environment, which we believe strengthens our operational performance. Our drilling activity is predominantly focused on the horizontal development of several prospective intervals, including multiple levels of the Wolfcamp formation and the Lower Spraberry shales. We have assembled a multi-year inventory of potential horizontal well locations and intend to add to this inventory through delineation drilling of emerging zones on our existing acreage and acquisition of additional locations through working interest acquisitions, leasing programs, acreage purchases, joint ventures and asset swaps. Our production was approximately 79% oil and 21% natural gas for the year ended December 31, 2018. On December 31, 2018, our net acreage position in the Permian Basin was 84,705 net acres.

Significant accomplishments for 2018 include:

- Increased annual production in 2018 by 44% to 12,018 MBOE as compared to 2017;
- Increased 2018 proved reserves by 74% to 239 MMBOE as compared to 2017;
- Generated an operating margin of $40.16 per BOE produced, reflecting our high oil mix and operating cost controls;
- Expanded our presence in the Delaware Basin through acquisitions of 30,000 net surface acres primarily adjacent to our existing position;
- Issued $400 million aggregate principal amount of its 6.375% Senior Notes;
- Completed an underwritten public offering of 25.3 million shares of common stock for total estimated net proceeds of approximately $288 million.
- Amended the borrowing base under our Credit Facility to $1.1 billion with a current elected commitment level of $850 million, providing us with additional liquidity.

Operational Highlights

All of our producing properties are located in the Permian Basin. As a result of our horizontal development and acquisition efforts, our production grew 44% in 2018 compared to 2017, increasing to 12,018 MBOE from 8,373 MBOE. Our production in 2018 was approximately 79% oil and 21% natural gas.

For the year ended December 31, 2018, we drilled 70 gross (57.5 net) horizontal wells, completed 65 gross (53.1 net) horizontal wells and had eleven gross (9.5 net) horizontal wells awaiting completion.

Reserve Growth

As of December 31, 2018, our estimated net proved reserves increased 74% to 238.5 MMBOE compared to 137.0 MMBOE of estimated net proved reserves at year-end 2017. Our significant growth in proved reserves was primarily attributable to our horizontal development and acquisition efforts. Our proved reserves at year-end 2018 and 2017 were 76% oil and 24% natural gas for both periods.

Management's Discussion and Analysis
of Financial Condition and Results of
Operation

Results of Operations

The following table sets forth certain operating information with respect to the Company's oil and natural gas operations for the periods indicated:

	Twelve Months Ended December 31,						
	2018	2017	Change	% Change	2016	Change	% Change
Net production							
Oil (MBbls)	9,443	6,557	2,886	44 %	4,280	2,277	53 %
Natural gas (MMcf)	15,447	10,896	4,551	42 %	7,758	3,138	40 %
Total (MBOE)	12,018	8,373	3,645	44 %	5,573	2,800	50 %
Average daily production (BOE/d)	32,926	22,940	9,986	44 %	15,227	7,713	50 %
% oil (BOE basis)	79 %	78 %			77 %		
Average realized sales price (excluding impact of settled derivatives)							
Oil (per Bbl)	$56.22	$49.16	$7.06	14 %	$41.51	$7.65	18 %
Natural gas (per Mcf)	3.67	4.05	(0.38)	(9)%	2.99	1.06	35 %
Total (per BOE)	48.90	43.77	5.13	12 %	36.04	7.73	21 %
Average realized sales price (including impact of settled derivatives)							
Oil (per Bbl)	$53.31	$47.78	$5.53	12 %	$45.67	$2.11	5 %
Natural gas (per Mcf)	3.69	4.10	(0.41)	(10)%	3.00	1.10	37 %
Total (per BOE)	46.63	42.76	3.87	9 %	39.25	3.51	9 %
Oil and natural gas revenues (in thousands)							
Oil revenue	$530,898	$322,374	$208,524	65 %	$177,652	$144,722	81 %
Natural gas revenue	56,726	44,100	12,626	29 %	23,199	20,901	90 %
Total	$587,624	$366,474	$221,150	60 %	$200,851	$165,623	82 %
Additional per BOE data							
Sales price [(a)]	$48.90	$43.77	$5.13	12 %	$36.04	$7.73	21 %
Lease operating expense [(b)]	5.76	5.46	0.30	5 %	6.56	(1.10)	(17)%
Gathering and treating expense [(c)]	—	0.50	(0.50)	(100)%	0.32	0.18	56 %
Production taxes	2.98	2.67	0.31	12 %	2.13	0.54	25 %