Oasis Petroleum Inc.
Form 10-K
March 01, 2019
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 1-34776

Oasis Petroleum Inc.
(Exact name of registrant as specified in its charter)

Delaware	80-0554627
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1001 Fannin Street, Suite 1500	
Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(281) 404-9500
(Registrant's telephone number, including area code)
Securities Registered Pursuant to Section 12(b) of the Act:

Common Stock, par value $0.01 per share	New York Stock Exchange
(Title of Class)	(Name of Exchange)

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No ¨
Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No ý
Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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

Large accelerated filer ý Accelerated filer ¨

Non-accelerated filer ¨ Smaller reporting company ¨

Emerging growth company ¨

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No ý

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant’s most recently completed second fiscal quarter: $4,124,266,176

Number of shares of registrant’s common stock outstanding as of February 22, 2019: 321,790,575

Documents Incorporated By Reference:

Portions of the registrant’s definitive proxy statement for its 2019 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2018, are incorporated by reference into Part III of this report for the year ended December 31, 2018.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this Annual Report on Form 10-K, regarding our strategic tactics, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report on Form 10-K, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about:

- our business strategic tactics;
- estimated future net reserves and present value thereof;
- timing and amount of future production of oil and natural gas;
- drilling and completion of wells;
- estimated inventory of wells remaining to be drilled and completed;
- costs of exploiting and developing our properties and conducting other operations;
- availability of drilling, completion and production equipment and materials;
- availability of qualified personnel;
- owning and operating a midstream company, including ownership interests in a master limited partnership;
- owning and operating a well services company;
- infrastructure for produced and flowback water gathering and disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston and Delaware Basins and other regions in the United States;
- property acquisitions, including our recent acquisition of oil and gas properties in the Delaware Basin;
- integration and benefits of property acquisitions or the effects of such acquisitions on our cash position and levels of indebtedness;
- the amount, nature and timing of capital expenditures;
- availability and terms of capital;
- our financial strategy, budget, projections, execution of business plan and operating results;
- cash flows and liquidity;
- oil and natural gas realized prices;
- general economic conditions;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- potential effects arising from cyber threats, terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- effectiveness of risk management activities;
- competition in the oil and natural gas industry;
- counterparty credit risk;
- environmental liabilities;
- governmental regulation and the taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;
- technology;
- the effects of accounting pronouncements issued periodically during the periods covered by forward-looking statements;
- uncertainty regarding future operating results;
- plans, objectives, expectations and intentions contained in this report that are not historical;
- our ability to remediate the identified material weakness in our internal control over financial reporting; and

• certain factors discussed elsewhere in this Form 10-K.

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements unless required by securities law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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PART I

Item 1. Business

Overview

Oasis Petroleum Inc. (together with our consolidated subsidiaries, the "Company," "we," "us," or "our") was originally formed in 2007 and was incorporated pursuant to the laws of the State of Delaware in 2010. We are an independent exploration and production ("E&P") company focused on the acquisition and development of onshore, unconventional oil and natural gas resources in the United States. Oasis Petroleum North America LLC ("OPNA") and Oasis Petroleum Permian LLC ("OP Permian") conduct our exploration and production activities and own our proved and unproved oil and natural gas properties located in the North Dakota and Montana regions of the Williston Basin and the Texas region of the Delaware Basin, respectively. We operate a midstream services business through OMS Holdings LLC ("OMS"), through which we own a majority of the outstanding units of Oasis Midstream Partners LP (NYSE: OMP) ("OMP" or "Oasis Midstream"), which completed its initial public offering on September 25, 2017. We also operate a well services business through Oasis Well Services LLC ("OWS").

As of December 31, 2018, we have accumulated 413,552 net leasehold acres in the Williston Basin, of which approximately 97% is held by production. We are currently exploiting significant resource potential from the Bakken and Three Forks formations, which are present across a substantial portion of our acreage. We believe the location, size and concentration of our acreage create an opportunity for us to achieve cost, recovery and production efficiencies through the development of our project inventory. In addition, on February 14, 2018, we closed on an acquisition of approximately 22,000 net acres in the Delaware Basin, representing our initial entry into the Delaware Basin (the "Permian Basin Acquisition"). The Permian Basin Acquisition more than doubled our core net inventory and allows us to further capitalize on our operational strengths. As of December 31, 2018, we have accumulated 23,366 net leasehold acres in the Delaware Basin, of which approximately 67% is held by production. Our management team has a proven track record in identifying, acquiring and executing large, repeatable development drilling programs, which we refer to as "resource conversion" opportunities, and has substantial Williston Basin and Delaware Basin experience.

In 2018, we completed and placed on production 121 gross operated wells and had average daily production of 82,525 barrels of oil equivalent per day ("Boepd") in the Williston and Delaware Basins. As of December 31, 2018, we had 1,053 gross (784.6 net) operated producing horizontal wells in the Bakken and Three Forks formations in the Williston Basin and 31 gross (29.5 net) operated producing horizontal wells in the Delaware Basin. As of December 31, 2018, DeGolyer and MacNaughton, our independent reserve engineers, estimated our net proved reserves to be 280.1 million barrels of oil equivalent ("MMBoe") in the Williston Basin, of which 67% were classified as proved developed and 70% were oil, and net proved reserves to be 40.5 MMBoe in the Delaware Basin, of which 30% were classified as proved developed and 80% were oil.

Our business

Our goal is to enhance value by investing capital to build reserves, production and cash flows at attractive rates of return through the following strategic tactics:

- Efficiently develop our Williston Basin and Delaware Basin leasehold positions. We are developing our acreage positions to maximize the value of our resource potential, while maintaining flexibility to preserve future value when oil prices are low. During 2018, we completed and brought on production 114 gross (79.0 net) operated wells in the Williston Basin and 7 gross (6.3 net) operated wells in the Delaware Basin. As of December 31, 2018, we had 64 gross operated wells waiting on completion in the Williston Basin and 4 gross operated wells awaiting completion in the Delaware Basin. Our 2019 capital plan contemplates completing and placing on production approximately 70 gross operated wells in the Williston Basin and approximately 9 to 11 gross operated wells in the Delaware Basin. We have the ability to increase or decrease the number of wells drilled and the number of wells completed during 2019 based on market conditions and program results.
- Enhance returns by focusing on operational and cost efficiencies. Our management team is focused on continuous improvement of our operations and has significant experience in successfully operating cost-efficient development programs. We believe the magnitude and concentration of our acreage within the Williston Basin, particularly in the core of the play, has provided and will continue to provide us with the opportunity to capture economies of scale, including the ability to drill multiple wells from a single drilling pad into multiple formations, utilize centralized

production and oil, gas and water fluid handling facilities and infrastructure, and reduce the time and cost of rig mobilization. The Permian Basin Acquisition enables us to transfer our technical, operational and managerial knowledge from full-field development of the Williston Basin to the Delaware Basin. In addition, we expect OMS and OWS to continue to provide operational synergies going forward compared to third party providers.

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- Adopt and employ leading drilling and completion techniques. Our team is focused on enhancing our drilling and completion techniques to maximize overall well economics. Completion techniques have significantly evolved over the past decade, resulting in increased initial production rates and recoverable hydrocarbons per well. High intensity completion techniques continue to deliver production performance greater than prior completion techniques. We continuously evaluate our internal drilling and completion results and monitor the results of other operators to improve our operating practices. This ongoing evolution may enhance our initial production rates, increase ultimate recovery factors, lower well capital costs and improve rates of return on invested capital.
- Maintain financial flexibility. Based on current market conditions, we have a strong liquidity position. We have no short-term debt maturities, and as of December 31, 2018, we had $972.2 million of liquidity available, including $22.2 million of cash and cash equivalents and $950.0 million in the aggregate of unused borrowing base capacity available under our Revolving Credit Facilities (as defined in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources"). Our liquidity position, along with internally generated cash flows from operations, will provide continued financial flexibility as we actively manage the pace of development on our acreage positions in the Williston Basin and the Delaware Basin. We currently believe we have access to the public and private capital markets, and we intend to maintain a balanced capital structure by prudently raising proceeds from future offerings as additional capital needs arise. We also continue to evaluate options to monetize certain assets in our portfolio, which could result in increased liquidity and lower leverage.
- Pursue strategic acquisitions with significant resource potential. As opportunities arise, we intend to identify and acquire additional acreage and producing assets to supplement our existing operations. On February 14, 2018, we completed the Permian Basin Acquisition, and going forward, we may acquire additional acreage in the Williston Basin and Delaware Basin or may selectively target additional basins that would allow us to employ our resource conversion strategy on large undeveloped acreage positions similar to what we have accumulated in the Williston Basin.

Our competitive strengths

We have a number of competitive strengths that we believe will help us to successfully execute our business strategies:

- Substantial leasehold position in two of North America's leading unconventional oil-resource plays. We believe our Williston Basin acreage is one of the largest concentrated leasehold positions that is prospective in the Bakken and Three Forks formations. As of December 31, 2018, we had 413,552 net leasehold acres in the Williston Basin, of which 400,711 net acres were held by production, and 70% of our 280.1 MMBoe estimated net proved reserves in this area were comprised of oil. In addition, we made our initial entry into one of the most prolific oil plays in North America, the Delaware Basin. As of December 31, 2018, we had 23,366 net leasehold acres in the Delaware Basin, of which 15,767 net acres were held by production, and 80% of our 40.5 MMBoe estimated net proved reserves in this area were comprised of oil. In 2019, we will continue our drilling and completion activities in the Williston Basin as well as in the Delaware Basin.
- Large, multi-year project inventory. We believe we have a large inventory of potential drilling locations that we have not yet drilled, a majority of which are operated by us, and the Permian Basin Acquisition more than doubled our top-tier inventory. We plan to complete approximately 70 gross operated wells with a working interest of approximately 65% in the Williston Basin and approximately 9 to 11 gross operated wells with a working interest of approximately 90% in the Delaware Basin in 2019.
- Management team with proven operating and acquisition skills. Our senior management team has extensive expertise in the oil and gas industry with an average of more than 25 years of industry experience, including experience in multiple North American resource plays as well as experience in international basins. We believe our management and technical team is one of our principal competitive strengths relative to our industry peers due to our team's proven track record in identification, acquisition and execution of resource conversion opportunities. In addition, our technical team possesses substantial expertise in horizontal drilling techniques and managing and acquiring large development programs.
- Incentivized management team. In 2018, an average of 70% of our executive officers' overall compensation was in long-term equity-based incentive awards, and such officers owned approximately 4.0 million shares of our

outstanding common stock as of December 31, 2018. We believe our executive officers' ownership interest in us provides them with significant incentives to grow the value of our business for the benefit of all stakeholders.

- Operating control over the majority of our portfolio. In order to maintain better control over our asset portfolio, we have established a leasehold position comprised primarily of properties that we expect to operate. As of December 31, 2018, 96% of our estimated net proved reserves were attributable to properties that we expect to operate. Approximately 94% of our 2018 drilling and completion capital expenditures and approximately 97% of our 2019 plan are related to operated wells. Controlling operations will allow us to dictate the pace of development and better manage the costs, type

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and timing of exploration and development activities. We believe that maintaining operational control over the majority of our acreage will allow us to better pursue our strategies of enhancing returns through operational and cost efficiencies and maximizing hydrocarbon recovery through continuous improvement of drilling and completion techniques. We are also better able to control infrastructure investment to drive down operating costs, optimize oil price realizations and increase the monetization of gas production.

- Vertical integration. Our investments in and operational control of OMS and OWS provide us with additional operational efficiencies and cost savings compared to our peers. This vertical integration helps us control capital dollars being spent in advance of production to ensure volumes flow, improve uptime performance of our producing wells, protect against rising service costs, increase transparency in the planning process and increase communications with vendors by purchasing directly from them.

Our operations - exploration and production activities

Proved reserves

Our estimated net proved reserves and related PV-10 at December 31, 2018, 2017 and 2016 are based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers. In preparing its reports, DeGolyer and MacNaughton evaluated 100% of the reserves and discounted values at December 31, 2018, 2017 and 2016 in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in oil and natural gas producing activities. Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure do not include probable or possible reserves and were determined using the preceding twelve months' unweighted arithmetic average of the first-day-of-the-month index prices for oil and natural gas, which were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $65.66 per Bbl for oil and $3.16 per MMBtu for natural gas, $51.34 per Bbl for oil and $2.99 per MMBtu for natural gas and $42.60 per Bbl for oil and $2.47 per MMBtu for natural gas for the years ended December 31, 2018, 2017 and 2016, respectively. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The information in the following table does not give any effect to or reflect our commodity derivatives. Future operating costs, production taxes and capital costs were based on current costs as of each year-end. For a definition of proved reserves under the SEC rules, please see the "Glossary of oil and natural gas terms" included at the end of this report. For more information regarding our independent reserve engineers, please see "Independent petroleum engineers" below. Future net revenues represent projected revenues from the sale of our estimated net proved reserves (excluding derivative contracts) net of production and development costs (including operating expenses and production taxes). PV-10 and Standardized Measure represent the present value of the future net revenues discounted at 10%, before and after income taxes, respectively.

There are numerous uncertainties inherent in estimating reserves and related information, and different reservoir engineers often arrive at different estimates for the same properties. There can be no assurance that our estimated net proved reserves will be produced within the periods indicated or that prices and costs will remain constant. A substantial or extended decline in oil prices could result in a significant decrease in our estimated net proved reserves and related future net revenues, Standardized Measure and PV-10 in the future.

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The following table summarizes our estimated net proved reserves and related future net revenues, Standardized Measure and PV-10:

	At December 31, 2018	2017	2016
Estimated proved reserves:			
Oil (MMBbls)	228.4	225.0	236.6
Natural gas (Bcf)	552.7	523.5	411.1
Total estimated proved reserves (MMBoe)	320.5	312.2	305.1
Percent oil	71 %	72 %	78 %
Estimated proved developed reserves:			
Oil (MMBbls)	144.5	150.6	152.3
Natural gas (Bcf)	339.4	301.1	229.6
Total estimated proved developed reserves (MMBoe)	201.1	200.8	190.6
Percent proved developed	63 %	64 %	62 %
Estimated proved undeveloped reserves:			
Oil (MMBbls)	83.9	74.3	84.3
Natural gas (Bcf)	213.3	222.4	181.5
Total estimated proved undeveloped reserves (MMBoe)	119.4	111.4	114.5
Future net revenues (in millions)	$8,341.6	$6,185.4	$4,645.6
Standardized Measure (in millions)(1)	$4,050.3	$3,300.7	$2,483.1
PV-10 (in millions)(2)	$4,674.3	$3,683.7	$2,627.8

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(1) Standardized Measure represents the present value of estimated future net cash flows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable financial measure under accounting principles generally accepted in the United States of America ("GAAP"), because it does not include the effect of income taxes on discounted future net cash flows. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas reserves. The oil and gas industry uses PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. See "Reconciliation of PV-10 to Standardized Measure" below.

The following table provides additional information regarding our estimated net proved developed and undeveloped oil and natural gas reserves by basin as of December 31, 2018:

	Proved Developed			Proved Undeveloped		
	Oil (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Oil (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)
Williston Basin	134.6	325.5	188.8	61.5	178.4	91.2
Delaware Basin	9.9	14.0	12.3	22.4	34.9	28.2
Total	144.5	339.5	201.1	83.9	213.3	119.4

Estimated net proved reserves at December 31, 2018 were 320.5 MMBoe, a 3% increase from estimated net proved reserves of 312.2 MMBoe at December 31, 2017, primarily due to increases of 38.4 MMBoe for additions and 32.9 MMBoe for acquisitions in the Delaware Basin, partially offset by a decrease of 30.1 MMBoe for production, net negative revisions of 16.9 MMBoe and 15.9 MMBoe for divestitures of non-strategic assets in the Williston Basin. The net negative revisions were attributable to negative revisions of 42.3 MMBoe due to well performance and 9.4 MMBoe associated with alignment to the five-year development plan, offset by positive revisions of 14.7 MMBoe for the addition of proved undeveloped reserves ("PUDs") that were previously removed from our five-year development plan, 14.4 MMBoe due to higher realized prices and 5.4 MMBoe for ownership adjustments. Our proved developed reserves increased 0.3 MMBoe, or 0.1%, to 201.1 MMBoe for the year ended December 31, 2018 from 200.8 MMBoe for the year ended December 31, 2017, primarily due to our 2018 development program, which included 137 gross (85.5 net) wells that were completed and brought on production during 2018

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and resulted in conversions of PUDs of 48.9 MMBoe and additions of 9.0 MMBoe. In addition, increases in proved developed reserves were due to purchases of 8.7 MMBoe, offset by decreases of 30.1 MMBoe for production, net negative revisions of 20.2 MMBoe and 15.9 MMBoe for divestitures. Proved developed revisions were primarily due to negative revisions of 33.0 MMBoe for performance largely related to higher than anticipated decline rates in recently developed spacing units, partially offset by positive revisions of 12.2 MMBoe due to higher realized prices. Our proved undeveloped reserves increased 8.0 MMBoe, or 7%, to 119.4 MMBoe for the year ended December 31, 2018 from 111.4 MMBoe for the year ended December 31, 2017 due to additions of 29.4 MMBoe, acquisitions of 24.2 MMBoe and net positive revisions of 3.4 MMBoe, offset by the conversion of wells to proved developed of 48.9 MMBoe. The proved undeveloped revisions were primarily due to positive revisions of 14.7 MMBoe for the addition of PUDs that were previously removed from our five-year development plan, 5.6 MMBoe for ownership adjustments and 2.2 MMBoe due to higher realized prices, offset by negative revisions of 9.4 MMBoe associated with alignment to the anticipated five-year development plan and 9.3 MMBoe for performance largely related to the associated impact of higher than anticipated decline rates in recently developed spacing units.

Estimated net proved reserves at December 31, 2017 were 312.2 MMBoe, a 2% increase from estimated net proved reserves of 305.1 MMBoe at December 31, 2016 primarily due to an increase of 51.2 MMBoe for additions, partially offset by a decrease of 24.1 MMBoe for production and net negative revisions of 19.2 MMBoe. These net negative revisions were attributable to negative revisions of 39.1 MMBoe due to well performance and 2.1 MMBoe for alignment to the anticipated five-year development plan, offset by positive revisions of 16.1 MMBoe due to higher realized prices and 2.5 MMBoe for ownership adjustments. Our proved developed reserves increased 10.2 MMBoe, or 5%, to 200.8 MMBoe for the year ended December 31, 2017 from 190.6 MMBoe for the year ended December 31, 2016, primarily due to our 2017 development program, which included 153 gross (63.0 net) wells that were completed and brought on production during 2017 and resulted in additions of 17.9 MMBoe and conversions of 32.0 MMBoe. These increases were partially offset by a decrease of 24.1 MMBoe for production and negative revisions of 14.2 MMBoe. Proved developed revisions were primarily due to negative revisions of 29.7 MMBoe for performance revisions largely related to higher than anticipated decline rates in recently developed spacing units, offset by positive revisions of 14.1 MMBoe from increased realized prices. Our proved undeveloped reserves decreased to 111.4 MMBoe for the year ended December 31, 2017 from 114.5 MMBoe for the year ended December 31, 2016 due to the conversion of wells to proved developed of 32.0 MMBoe and negative revisions of 5.0 MMBoe, partially offset by 33.3 MMBoe of additions. The proved undeveloped revisions were primarily due to negative revisions of 9.4 MMBoe for performance revisions largely related to the associated impact of higher than anticipated decline rates in recently developed spacing units and negative revisions of 1.8 MMBoe associated with alignment to the five-year development plan, offset by positive revisions of 2.6 MMBoe for ownership adjustments and 2.0 MMBoe from increased realized prices. In 2017, we divested 1.4 MMBoe of reserves associated with reservoirs other than the Bakken or Three Forks formations.

Reconciliation of Standardized Measure to PV-10

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of the Standardized Measure of discounted future net cash flows to PV-10:

	At December 31,		
	2018	2017	2016
		(In millions)	
Standardized Measure of discounted future net cash flows	$4,050.3	$ 3,300.7	$2,483.1
Add: present value of future income taxes discounted at 10%	624.0	383.0	144.7
PV-10	$4,674.3	$ 3,683.7	$2,627.8

The PV-10 of our estimated net proved reserves at December 31, 2018 was $4,674.3 million, a 27% increase from PV-10 of $3,683.7 million at December 31, 2017. This increase was primarily due to higher commodity price assumptions and an increase in reserves year over year.

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Proved undeveloped reserves

At December 31, 2018, we had approximately 119.4 MMBoe of proved undeveloped reserves as compared to 111.4 MMBoe at December 31, 2017.

The following table summarizes the changes in our proved undeveloped reserves during 2018:

	Year Ended December 31, 2018
	(MBoe)
Proved undeveloped reserves, beginning of period	111,392
Extensions, discoveries and other additions	29,384
Purchases of minerals in place	24,194
Sales of minerals in place	—
Revisions of previous estimates	3,387
Conversion to proved developed reserves	(48,927)
Proved undeveloped reserves, end of period	119,430

During 2018, we spent a total of $659.3 million related to the development of proved undeveloped reserves, $79.2 million of which was spent on proved undeveloped reserves that represent wells in progress at year-end. The remaining $580.1 million resulted in the conversion of 48.9 MMBoe of proved undeveloped reserves, or 44% of our proved undeveloped reserves balance at the beginning of 2018, to proved developed reserves. We added 29.4 MMBoe of proved undeveloped reserves as a result of our five-year development plan. The 2018 proved undeveloped revisions of 3.4 MMBoe were primarily due to positive revisions of 14.7 MMBoe for the addition of PUDs that were previously removed from our five-year development plan, 5.6 MMBoe for ownership adjustments and 2.2 MMBoe due to higher realized prices, offset by negative revisions of 9.4 MMBoe associated with alignment to the anticipated five-year development plan and 9.3 MMBoe for performance largely related to the associated impact of higher than anticipated decline rates in recently developed spacing units.

We expect to develop all of our proved undeveloped reserves, including all wells drilled but not yet completed, as of December 31, 2018 within five years after the initial year booked. The future development of such proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecasts as well as access to liquidity sources, such as capital markets, our Revolving Credit Facilities and our derivative contracts. All proved undeveloped locations are located on properties where the leases are held by existing production or continuous drilling operations. Approximately 15% of our proved undeveloped reserves at December 31, 2018 are attributable to wells that have been drilled but not yet completed, and 74% and 26% of our undrilled reserves are within our core acreage in the Williston Basin and Delaware Basin, respectively.

Independent petroleum engineers

Our estimated net proved reserves and related future net revenues and PV-10 at December 31, 2018, 2017 and 2016 are based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers, by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007) and definitions and current guidelines established by the SEC. DeGolyer and MacNaughton is a Delaware corporation with offices in Dallas, Houston, Moscow, Astana, Buenos Aries, Baku and Algiers. The firm’s more than 200 professionals include engineers, geologists, geophysicists, petrophysicists and economists engaged in the appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies and equity studies related to the domestic and international energy industry. DeGolyer and MacNaughton has provided such services for over 80 years. The Senior Vice President at DeGolyer and MacNaughton primarily responsible for overseeing the preparation of the reserve estimates is a Registered Professional Engineer in the State of Texas with over 30 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from The University of Texas at Austin in 1984, and he is a member of the Society of Petroleum Engineers and the Society of Petroleum

Evaluation Engineers. DeGolyer and MacNaughton restricts its activities exclusively to consultation; it does not accept contingency fees, nor does it own operating interests in any oil, gas or mineral properties, or securities or notes of clients. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies. The firm is a Texas Registered Engineering Firm.

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Technology used to establish proved reserves

In accordance with rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" means deterministically, the quantities of oil and/or natural gas are much more likely to be achieved than not, and probabilistically, there should be at least a 90% probability of recovering volumes equal to or exceeding the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by using reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007). The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by us to DeGolyer and MacNaughton and the analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

A performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for the evaluation of all reserves categories. Performance-based methodology primarily includes (i) production diagnostics, (ii) decline-curve analysis and (iii) model-based analysis (if necessary, based on the availability of data). Production diagnostics include data quality control, identification of flow regimes and characteristic well performance behavior. Analysis was performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model based analysis may be integrated to evaluate long-term decline behavior, the impact of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs. The methodology used for the analysis was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, production history and appropriate reserves definitions.

Internal controls over reserves estimation process

We employ DeGolyer and MacNaughton as the independent reserves evaluator for 100% of our reserves base. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with the independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished for the reserves estimation process. Brett Newton, Senior Vice President of Asset Management and Chief Engineer, is the technical person primarily responsible for overseeing our reserves evaluation process. He has over 25 years of industry experience with positions of increasing responsibility in engineering and management. He holds both a Bachelor of Science degree and Master of Science degree in petroleum engineering. Mr. Newton reports directly to our President and Chief Operating Officer.

Throughout each fiscal year, our technical team meets with the independent reserve engineers to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data into our reserves evaluation software as well as management review, such as, but not limited to the following:

- Comparison of historical expenses from the lease operating statements and workover authorizations for expenditure to the operating costs input in our reserves database;
- Review of working interests and net revenue interests in our reserves database against our well ownership system;
-

Review of historical realized prices and differentials from index prices as compared to the differentials used in our reserves database;

- Review of updated capital costs prepared by our operations team;
- Review of internal reserve estimates by well and by area by our internal reservoir engineers;
- Discussion of material reserve variances among our internal reservoir engineers and our Senior Vice President of Asset Management and Chief Engineer;

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- Review of a preliminary copy of the reserve report by our President and Chief Operating Officer with our internal technical staff; and
- Review of our reserves estimation process by our Audit Committee on an annual basis.

Production, revenues, price and cost history

We produce and market oil and natural gas, which are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, access to markets, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Oil supply in the United States has grown dramatically over the past several years, putting downward pressure on oil prices. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil and natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—A substantial or extended decline in commodity prices, in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

The following table sets forth information regarding our oil and natural gas production, realized prices and production costs for the periods indicated. For additional information on price calculations, please see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,		
	2018	2017	2016
Net production volumes:			
Oil (MBbls)	23,050	18,818	15,174
Natural gas (MMcf)	42,430	31,946	19,573
Oil equivalents (MBoe)	30,122	24,143	18,436
Average daily production (Boe per day)	82,525	66,144	50,372
Average sales prices:			
Oil, without derivative settlements (per Bbl)	$ 61.84	$ 48.51	$ 38.64
Oil, with derivative settlements (per Bbl)(1)	52.65	47.99	46.68
Natural gas, without derivative settlements (per Mcf)(2)	3.88	3.81	1.99
Natural gas, with derivative settlements (per Mcf)(1)(2)	3.84	3.86	1.99
Costs and expenses (per Boe of production):			
Lease operating expenses	$ 6.44	$ 7.34	$ 7.35
Marketing, transportation and gathering expenses(3)	3.56	2.31	1.63
Production taxes	4.44	3.65	3.07
Exploration and production general and administrative expenses	3.40	3.21	4.28
Cash E&P G&A(4)	2.48	2.16	3.02

(1) Realized prices include gains or losses on cash settlements for our commodity derivatives, which do not qualify for or were not designated as hedging instruments for accounting purposes. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

(2) Natural gas prices include the value for natural gas and natural gas liquids.

(3) Prior to the first quarter of 2017, marketing, transportation and gathering expenses included purchased oil and gas expenses, which represent the crude oil purchased primarily for blending at our crude oil terminal. Prior periods have been adjusted retrospectively to reflect these expenses in purchased oil and gas expenses on our Consolidated Statements of Operations. For the year ended December 31, 2016, marketing, transportation and gathering expenses have been adjusted to exclude $10.3 million of purchased oil and gas expenses.

(4)

Cash E&P G&A, a non-GAAP measure, represents general and administrative expenses less non-cash equity-based compensation expenses included in our exploration and production segment. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Measures” for a reconciliation of our exploration and production segment general and administrative expenses to Cash E&P G&A.

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Net production volumes for the year ended December 31, 2018 were 30,122 MBoe as compared to net production of 24,143 MBoe for the year ended December 31, 2017. Our net production volumes increased from 2017 to 2018, primarily due to our acquisition of producing properties in connection with the Permian Basin Acquisition and a successful operated and non-operated drilling and completion program, offset by the natural decline in production in wells that were producing as of December 31, 2017. Average oil sales prices, without derivative settlements, increased by $13.33 per barrel, or 27%, to an average of $61.84 per barrel for the year ended December 31, 2018 as compared to the year ended December 31, 2017. Giving effect to our derivative transactions in both periods, our oil sales prices increased $4.66 per barrel to $52.65 per barrel for the year ended December 31, 2018 from $47.99 per barrel for the year ended December 31, 2017.

Net production volumes for the year ended December 31, 2017 were 24,143 MBoe as compared to net production of 18,436 MBoe for the year ended December 31, 2016. Our net production volumes increased from 2016 to 2017 primarily due to our acquisition of producing properties in December 2016 and a successful operated and non-operated drilling and completion program, offset by the natural decline in production in wells that were producing as of December 31, 2016. Average oil sales prices, without derivative settlements, increased by $9.87 per barrel, or 26%, to an average of $48.51 per barrel for the year ended December 31, 2017 as compared to the year ended December 31, 2016. Giving effect to our derivative transactions in both periods, our oil sales prices increased $1.31 per barrel to $47.99 per barrel for the year ended December 31, 2017 from $46.68 per barrel for the year ended December 31, 2016.

Productive wells

The following table presents the total and operated gross and net productive wells by basin as of December 31, 2018:

	Total wells		Operated wells	
	Gross	Net	Gross	Net
Williston Basin - horizontal wells	1,400	825.7	1,053	784.6
Williston Basin - other	1	1.0	1	1.0
Delaware Basin - horizontal wells	103	30.1	31	29.5
Delaware Basin - other	38	22.3	19	17.1
Total wells	1,542	879.1	1,104	832.2

All of our productive wells are oil wells. Gross wells are the number of wells, operated and non-operated, in which we own a working interest and net wells are the total of our working interests owned in gross wells.

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage by basin in which we own a working interest as of December 31, 2018. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin	467,100	356,766	89,883	56,786	556,983	413,552
Delaware Basin	18,090	12,110	20,621	11,257	38,711	23,367
Total	485,190	368,876	110,504	68,043	595,694	436,919

Our total acreage that is held by production decreased to 416,478 net acres at December 31, 2018 from 480,023 net acres at December 31, 2017.

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Undeveloped acreage

The following table sets forth the number of gross and net undeveloped acres by basin as of December 31, 2018 that will expire over the next three years unless production is established on the acreage prior to the expiration dates:

	Year ending December 31,					
	2019		2020		2021	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin	2,320	1,894	10,420	7,763	2,430	2,299
Delaware Basin	966	826	3,454	1,228	827	156
Total	3,286	2,720	13,874	8,991	3,257	2,455

Drilling and completion activity

The following table summarizes our completion activity for the years ended December 31, 2018, 2017 and 2016. Gross wells reflect the sum of all productive and dry wells, operated and non-operated, in which we own a working interest. Net wells reflect the sum of our working interests in gross wells. The gross and net wells represent wells completed during the periods presented, regardless of when drilling was initiated.

	Year ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	135	84.2	153	63.0	64	38.1
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total development wells	135	84.2	153	63.0	64	38.1
Exploratory wells:						
Oil	2	1.3	—	—	—	—
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	2	1.3	—	—	—	—
Total wells	137	85.5	153	63.0	64	38.1

Over the past several years, we have focused on full field development and have concentrated on improving capital efficiency and completing more wells using high-intensity completion techniques. We also continued to participate in a number of wells on a non-operated basis.

We did not drill any dry hole wells in 2018, 2017 or 2016.

As of December 31, 2018, we had six operated rigs running, 6 gross (4.2 net) operated wells drilling and an inventory of 68 gross operated wells waiting on completion. We expect to continue to concentrate drilling activities within our top-tier acreage in 2019, including our acreage in the Bakken and Three Forks formations in the Williston Basin as well as our acquired acreage in the Bone Spring and Wolfcamp formations in the Delaware Basin.

Capital expenditures

In 2018, we spent $1,925.8 million on capital expenditures, excluding midstream capital expenditures, which represented a 220.4% increase as compared to the $601.1 million spent on capital expenditures, excluding midstream, during 2017. Excluding acquisitions of $951.9 million in 2018, which includes the Permian Basin Acquisition, and $54.0 million in 2017, our non-midstream capital expenditures increased to $974.0 million from the $547.1 million spent during 2017, which represented a 78.0% increase year over year. This increase was attributable to increased drilling and completion activity as a result of higher commodity prices in 2018. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Cash flows used in investing activities."

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We have decreased our planned 2019 capital expenditures as compared to 2018, excluding acquisitions and midstream, as a result of current commodity prices. Our total 2019 capital expenditure plan, excluding midstream capital expenditures, is approximately $540 million to $560 million, which includes approximately $405 million to $420 million focused in the Williston Basin and approximately $135 million to $140 million focused in the Delaware Basin (with approximately 85% of the E&P capital allocated to drilling and completions). In addition, our 2019 planned capital expenditures includes other capital expenditures for OWS and administrative capital and excludes capitalized interest of approximately $15 million. We plan to complete and place on production approximately 70 gross operated wells in the Williston Basin and approximately 9 to 11 gross operated wells in the Delaware Basin in 2019.

While we have planned approximately $540 million to $560 million in 2019 for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling results as the year progresses. Additionally, if we acquire additional acreage, our capital expenditures may be higher than planned. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Description of properties

As of December 31, 2018, we had 101 gross (56.7 net) wells in the process of being drilled or completed in the Williston and Delaware Basins, which includes 6 gross operated wells drilling, 68 gross operated wells waiting on completion and 27 gross non-operated wells drilling or completing. We participated in 137 gross (85.5 net) wells that were completed and brought on production during 2018.

Williston Basin

As of December 31, 2018, our operations were focused in the North Dakota and Montana areas of the Williston Basin. Our development activities are currently concentrated in the Bakken and Three Forks formations. Our management team originally targeted the Williston Basin because of its oil-prone nature, multiple producing horizons, substantial resource potential and management's previous professional history in the basin. The Williston Basin also generally has established infrastructure and access to materials and services. Our development activity is focused in the deepest part of the Williston Basin, which we call our top-tier acreage.

As of December 31, 2018, our total leasehold position in the Williston Basin consisted of 413,552 net acres, and our estimated net proved reserves in the Williston Basin were 280.1 MMBoe, of which 188.8 MMBoe were proved developed reserves and 91.2 MMBoe were proved undeveloped reserves. As of December 31, 2018, we had a total of 826.7 net producing wells and 785.6 net operated producing wells in the Williston Basin. We had average daily production of 78,203 net Boe per day for the year ended December 31, 2018 in the Williston Basin. During 2018, our Bakken and Three Forks wells produced a daily average of 78,168 net Boe per day with 784.6 net operated producing wells on December 31, 2018. Accordingly, our 784.6 net operated producing Bakken and Three Forks wells were responsible for nearly 100% of our average daily production during 2018. As of December 31, 2018, our working interest for all producing Bakken and Three Forks wells averaged 59% and averaged 75% in the wells we operate.

Delaware Basin

On February 14, 2018, we closed the Permian Basin Acquisition, which represented our initial entry into the Delaware Basin. The assets underlying the Permian Basin Acquisition are primarily located in the Bone Spring and Wolfcamp formations of the Delaware sub-basin, across Ward, Winkler, Loving and Reeves Counties, Texas.

As of December 31, 2018, our total leasehold position in the Delaware Basin consisted of 23,366 net acres, and our estimated net proved reserves in the Delaware Basin were 40.5 MMBoe, of which 12.3 MMBoe were proved developed reserves and 28.2 MMBoe were proved undeveloped reserves. As of December 31, 2018, we had a total of 52.4 net producing wells and 46.6 net operated producing wells in the Delaware Basin. We had average daily production of 4,322 net Boe per day for the year ended December 31, 2018 in the Delaware Basin. During 2018, our horizontal wells in the Delaware Basin produced a daily average of 4,164 net Boe per day with 29.5 net operated producing wells on December 31, 2018. Accordingly, our 29.5 net operated producing horizontal wells in the Delaware Basin were responsible for nearly 96% of our average daily production during 2018. As of December 31, 2018, our working interest for all producing horizontal wells in the Delaware Basin averaged 29% and in the wells we operate averaged 95%.

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Continuous Development Agreement. In connection with the closing of the Permian Basin Acquisition, Forge Energy, LLC ("Forge Energy") entered into and assigned to OP Permian a continuous development agreement with the Commissioner of the General Land Office, on behalf of the State of Texas (collectively, the "State"), as approved by the Board for Lease of University Lands (the "Board," and together with the State, "University Lands"). This agreement concerns certain leases covering a substantial portion of the acreage that the Company indirectly acquired from Forge Energy in the Permian Basin Acquisition and under which University Lands is the lessor. Pursuant to this agreement, the tracts covered by these leases are pooled into a single development area for which the Company indirectly holds an eight year initial term ending on December 31, 2025, with an additional five year term for certain retained acreage at certain depths in the Delaware, Bone Springs and Wolfcamp formations. If OP Permian fails to meet certain drilling and development obligations, this agreement may be subject to early termination, in which case, the additional five year term would begin on such date and we may be obligated to pay non-performance fees of up to approximately $100 million.

Marketing, transportation and major customers

The Williston Basin crude oil rail and pipeline transportation and refining infrastructure has grown substantially over the past decade, largely in response to drilling activity in the Bakken and Three Forks formations. In December 2018, oil production in North Dakota was approximately 1,401,000 barrels per day. According to the North Dakota Pipeline Authority website's data last updated January 15, 2019, there was approximately 1,421,000 barrels per day of combined crude oil pipeline transportation and refining capacity and approximately 1,520,000 barrels per day of specifically dedicated rail loading capacity in the Williston Basin as of December 31, 2018. In 2018, we continued to sell a significant amount of our crude oil production through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which typically originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. As of December 31, 2018, we were flowing approximately 88% of our gross operated oil production through these gathering systems in the Williston Basin. In the Delaware Basin, approximately 51% of our gross operated oil production was connected to oil gathering systems as of December 31, 2018.

Crude oil produced and sold in the Williston Basin has historically sold at a discount to the NYMEX West Texas Intermediate crude oil index price ("WTI") due to transportation costs and takeaway capacity. In the past, there have been periods when this discount has substantially increased due to the production of oil in the area increasing to a point that it temporarily surpasses the available pipeline transportation, rail transportation and refining capacity in the area. Expansions of both rail and pipeline facilities have reduced the prior constraint on oil transportation out of the Williston Basin and improved netback pricing received at the lease. In 2015, our price differentials relative to WTI strengthened as new pipelines opened to eastern Canada and U.S. markets and transportation on rail gradually declined. Since 2016, our price differentials have averaged less than $5.00 per barrel discount to WTI. In the second half of 2017 and throughout most of 2018, our crude oil price differentials improved to less than $2.00 per barrel discount to WTI primarily due to the additional takeaway capacity of the Dakota Access Pipeline of over 500,000 barrels per day. In the fourth quarter of 2018, above average refinery maintenance combined with production in the basin reaching record levels temporarily caused basis differentials to widen to more than $6.50 per barrel discount to WTI, but have since come back in line with the first three quarters of 2018. Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations. In the Delaware Basin, price differentials in 2018 averaged more than $4.00 per barrel below WTI due to pipeline constraints. Expansions of pipelines occurring in 2019 should greatly reduce these differentials and provide ample takeaway for our Delaware production beginning in mid-2019. For a discussion of the potential risks to our business that could result from transportation and refining infrastructure constraints in the Williston Basin, please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Insufficient transportation, end-market refining utilization or natural gas processing capacity in the Williston Basin and Delaware Basin could cause significant fluctuations in our realized oil and natural gas prices."

We principally sell our oil and natural gas production to refiners, marketers and other purchasers that have access to nearby pipeline and rail facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For a description of some of these factors, please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production" and "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Insufficient transportation, end-market refining utilization or natural gas processing capacity in the Williston Basin and Delaware Basin could cause significant fluctuations in our realized oil and natural gas prices."

In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broad array of potential purchasers. As of December 31, 2018, we sold a substantial majority of our oil and condensate through bulk sales at delivery points on crude oil gathering systems to a variety of purchasers at prevailing market prices under short-term contracts that normally provide for us to receive a market-based price, which incorporates regional differentials that include, but are not limited to, transportation costs. In addition, from time to time we may enter into third party purchase and sales transactions that allow us to optimize our advantageous gathering and transportation positions and increase the value of our oil price realizations. We also entered into various short-term sales contracts for a portion of our portfolio at fixed differentials. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows.

For the year ended December 31, 2018, no purchaser accounted for more than 10% of the Company's total sales. For the year ended December 31, 2017, sales to Shell Trading (US) Company accounted for approximately 16% of our total sales. For the year ended December 31, 2016, sales to PBF Holding Company LLC accounted for approximately 10% of our total sales. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2017 and 2016. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are a number of alternative crude oil and natural gas purchasers in the Williston and Delaware Basins.

Since most of our oil and natural gas production is sold under market-based or spot market contracts, the revenues generated by our operations are highly dependent upon the prices of and demand for oil and natural gas. The price we receive for our oil and natural gas production depends upon numerous factors beyond our control, including but not limited to seasonality, weather, competition, availability of transportation and gathering capabilities, worldwide and regional economic conditions, global and domestic oil supply, foreign imports, political conditions in other oil-producing and natural gas-producing regions, the actions of the Organization of Petroleum Exporting Countries ("OPEC") and domestic government regulation, legislation and policies. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—A substantial or extended decline in commodity prices, in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments." Furthermore, a decrease in the price of oil and natural gas could have an adverse effect on the carrying value of our estimated proved reserves and on our revenues, profitability and cash flows. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—If oil and natural gas prices decline substantially or for an extended period of time from their current levels, we may be required to take write-downs of the carrying values of our oil and natural gas properties."

Market, economic, transportation and regulatory factors may in the future materially affect our ability to market our oil or natural gas production. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production."

Our operations - midstream services

We continue to develop our midstream services business, which includes produced and flowback water gathering and disposal, natural gas gathering, compression and processing, fresh water supply and distribution and crude oil gathering and transportation. Our midstream services assets are strategically located in the Williston Basin and Delaware Basin and support our upstream operations. These assets also provide services to third party customers.

Our midstream services operations include those of OMP, a publicly-traded consolidated subsidiary and limited partnership that owns, develops, operates and acquires a diversified portfolio of midstream assets in North America. OMP is a growth-oriented, fee-based master limited partnership we formed in 2014 and organized in a development company structure. On September 25, 2017, OMP completed its initial public offering ("IPO") of common units. At December 31, 2018, our ownership interest in OMP consisted of a 67.6% limited partner interest and 90% controlling interest in its general partner interest, which owns all of OMP's incentive distribution rights and its non-economic general partner interest. OMP conducts its operations through its three development companies (collectively, the "DevCos"): Bighorn DevCo LLC ("Bighorn DevCo"), Bobcat DevCo LLC ("Bobcat DevCo") and Beartooth DevCo LLC ("Beartooth DevCo").

OMP divides its operations into two primary areas with developed midstream infrastructure, both of which are supported by significant acreage dedications from us. In Wild Basin, we have dedicated to OMP approximately 65,000 acres, of which approximately 29,000 acres are within our current gross operated acreage position, and in which OMP has the right to provide oil, natural gas and water services to support our existing and future volumes. Outside of Wild Basin, we have dedicated to OMP approximately 581,000 acres for produced and flowback water services, of which approximately 299,000 acres are within our current gross operated acreage. In addition, we have dedicated to OMP approximately 364,000 acres for freshwater services, of which approximately 203,000 acres are within our current gross operated acreage. In addition, OMP has received certain commitments from third parties in which OMP has the right to provide its full suite of midstream services to support existing and future third party volumes.

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Contractual arrangements

In connection with the OMP IPO, we entered into several 15-year, fee-based contractual arrangements with OMP for midstream services, including (i) gas gathering, compression, processing and gas lift services; (ii) crude gathering, stabilization, blending, storage and transportation services; (iii) produced and flowback water gathering and disposal services; and (iv) freshwater supply and distribution services. In addition, we provide substantial labor and overhead support for OMP. Upon completion of the OMP IPO, we entered into a 15-year services and secondment agreement with OMP pursuant to which we provide all personnel, equipment, electricity, chemicals and services (including third-party services) required for OMP to operate such assets, and OMP reimburses us for its share of the actual costs of operating such assets. In addition, pursuant to the services and secondment agreement, we perform centralized corporate, general and administrative services for OMP, such as legal, corporate recordkeeping, planning, budgeting, regulatory, accounting, billing, business development, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, investor relations, cash management and banking, payroll, internal audit, taxes and engineering. We have also seconded to OMP certain of its employees to operate, construct, manage and maintain its assets, and OMP reimburses us for direct general and administrative expenses we incurred for the provision of the above services. The expenses of executive officers and non-executive employees are allocated to OMP based on the amount of time spent managing its business and operations.

OMP public offering and dropdown

On November 14, 2018, OMP completed a public offering of 2,300,000 common units (including 300,000 common units issued pursuant to the underwriters' option to purchase additional common units) representing limited partnership interests, at a price to the public of $20.00 per common unit. OMP received net proceeds from the public offering of approximately $44.5 million, after deducting underwriting discounts, commissions and offering costs, which were used to fund a portion of its acquisition of additional ownership interest in Bobcat DevCo and Beartooth DevCo.

In connection with the OMP public offering, on November 19, 2018, OMP acquired an additional 15% ownership interest in Bobcat DevCo increasing its ownership to 25% and an additional 30% ownership interest in Beartooth DevCo increasing its ownership to 70% in exchange for consideration of $251.4 million ("OMP Dropdown").

The $251.4 million consideration consisted of $172.4 million in cash and 3,950,000 common units representing limited partner interests in OMP. OMP funded the cash portion of the consideration with a combination of borrowings under the revolving credit facility among OMP, as parent, OMP Operating LLC, a subsidiary of OMP, as borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "OMP Credit Facility") and proceeds from its public offering of common units. As a result of the OMP Dropdown, we now own 75% of the non-controlling interests of Bobcat DevCo and 30% of the non-controlling interests of Beartooth DevCo.

Capital expenditures

In 2018, midstream capital expenditures primarily related to the second natural gas processing plant constructed in our Wild Basin area in North Dakota and the development of additional midstream infrastructure in the Wild Basin area in North Dakota. We have decreased our planned 2019 midstream capital expenditures, excluding acquisitions, to approximately $150.0 million to $170.0 million as compared to 2018 midstream capital expenditures, excluding acquisitions.

Competition

The oil and natural gas industry is worldwide and highly competitive in all phases. We encounter competition from other oil and natural gas companies in all areas of operation, including the acquisition of leasing options on oil and natural gas properties to the exploration and development of those properties. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than we do. Such companies may be able to pay more for lease options on oil and natural gas properties and exploratory locations and to define, evaluate, bid for and purchase a greater number of properties and locations than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Please see "Item 1A. Risk

Factors—Risks related to the oil and natural gas industry and our business—Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel."

Title to properties

As is customary in the oil and gas industry, we initially conduct a preliminary review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant title defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with general industry standards. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of the properties, we may obtain a title opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our Revolving Credit Facilities, liens for current taxes and other burdens, which we believe do not materially interfere with the use or affect our carrying value of the properties. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—We may incur losses as a result of title defects in the properties in which we invest."

Seasonality

Winter weather conditions and lease stipulations can limit or temporarily halt our drilling, completion and producing activities and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

Regulation of the oil and natural gas industry

Our oil and natural gas producing, midstream and well services operations are substantially affected by federal, tribal, regional, state and local laws and regulations. In particular, oil and natural gas production, oil gathering and transportation, natural gas processing and related operations are, or have been, subject to price controls, taxes and numerous laws and regulations. All of the jurisdictions in which we own or operate properties for oil and natural gas production or otherwise provide midstream services have statutory provisions regulating the exploration for and production of oil and natural gas or the gathering, transportation and processing of those commodities, including provisions related to permits for the drilling of wells or processing of natural gas, bonding requirements to drill or operate producing or injection wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled or processing plants are constructed, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, the siting of processing plants, disposal wells and gathering or transportation lines, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Historically, our compliance costs with applicable laws and regulations have not had a material adverse effect on our financial position, cash flows and results of operations; however, new laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement may occur and, thus, there can be no assurance that such costs will not be material in the future. Additionally, environmental incidents such as spills or other releases may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may be finalized and become effective.

Regulation of transportation and sales of oil

Sales of crude 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.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to prescribed ceiling levels that are tied to changes in the Producer Price Index, without making a cost of service filing. Many existing pipelines utilize the FERC oil index to change transportation rates annually every July 1, and our Bighorn DevCo Johnson's Corner line will utilize the FERC oil index beginning on July 1, 2022. Every five years, FERC reviews the appropriateness of the index level in relation to changes in industry costs. Most recently, on December 17, 2015, FERC established a new price index for the five-year period commencing July 1, 2016 and ending June 30, 2021, in which common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by Producer Price Index plus 1.23%.

On March 15, 2018, in a set of related issuances, FERC addressed treatment of federal income tax allowances in regulated entity rates. FERC issued a Revised Policy Statement on Treatment of Income Taxes ("Revised Policy Statement") stating that, among other things and with respect to oil and refined products pipelines subject to FERC jurisdiction, the pipeline is required to reflect the impacts to its cost of service from the Revised Policy Statement and the Tax Cuts and Jobs Act of 2017 (the "Tax Act") on Page 700 of FERC Form No. 6. This information will be used by FERC in its next five-year review of the oil pipeline index to generate the index level to be effective July 1, 2021, thereby including the effect of the Revised Policy Statement and the Tax Act in the determination of indexed rates prospectively, effective July 1, 2021. FERC's establishment of a just and reasonable rate, including the determination of the appropriate oil pipeline index, is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect FERC's determination of the appropriate pipeline index. Accordingly, depending on FERC's application of its indexing rate methodology for the next five-year term of index rates, the Revised Policy Statement and tax effects related to the Tax Act may impact our revenues associated with any transportation services we may provide pursuant to cost-of-service based rates in the future, including indexed 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 way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally 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 similarly situated competitors.

We sell a significant amount of our crude oil production through gathering systems connected to rail facilities. Several derailments of freight trains since 2013 have led transportation safety regulators in the United States and Canada to examine whether the hazardous nature of crude oil from the Bakken shale is being assessed properly prior to its shipment. In particular, there are concerns that the testing and ensuing designations of crude oil on the shipping documentation do not in all cases accurately capture the flammability of the Bakken shale crude oil. In early 2014, the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") released a Safety Alert alerting regulators, emergency responders, transporters and shippers that crude oil from the Bakken shale may have flammability characteristics that are different from other forms of crude oil and that it was vital that all shipments of crude oil be tested and properly characterized on all shipping documentation. The Safety Alert also notified the regulated community that PHMSA and the Federal Railroad Administration ("FRA") had launched an enforcement initiative that involved unannounced inspections on crude oil shipments to test the contents of the shipments in order to ensure that they are properly characterized. In 2014, the U.S. Department of Transportation released a report finding that, based on the results of this enforcement initiative from August 2013 to May 2014, Bakken shale crude oil tended to be more volatile and flammable than other crude oils, and thus posed an increased risk for a significant accident.

These events have also spurred efforts to improve the safety of tank cars that are used in transporting crude oil by rail. Since 2011, all new railroad tank cars that have been built to transport crude oil or other petroleum type fluids, including ethanol, have been built to more stringent safety standards. In 2015, PHMSA adopted a final rule that included, among other things, additional requirements to enhance tank car standards for certain trains carrying crude oil and ethanol, a classification and testing program for crude oil, and a requirement that older DOT-111 tank cars be phased out beginning in October 2017 if they are not already retrofitted to comply with new tank car design standards. The 2015 final rule also included a new braking standard for certain trains, designated new operational protocols for trains transporting large volumes of flammable liquids, such as routing analyses, speed restrictions and information for local government agencies and provided new sampling and testing requirements to improve classification of energy products placed into transport; however, in September 2018, PHMSA published a final rule that removed requirements for the new braking standard established under its 2015 final rule. In 2016, PHMSA released a final rule mandating a phase-out schedule for all DOT-111 tank cars used to transport Class 3 flammable liquids, including crude oil and ethanol, between 2018 and 2029. Additionally, in 2016, PHMSA proposed a new rule, which has not yet been finalized, that would expand the applicability of comprehensive oil spill response plans so that any railroad that transports a single train carrying 20 or more loaded tanks of liquid petroleum oil in a continuous block or a single train

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carrying 35 or more loaded tank cars of liquid petroleum oil throughout the train must have a current, comprehensive, written plan. Also, in response to a petition from the New York Attorney General, PHMSA issued an advance notice of proposed rulemaking (“ANPR”) in early 2017 stating that it was considering revising the Hazardous Materials Regulations to establish vapor pressure limits for unrefined petroleum-based products and potentially all Class 3 flammable liquid hazardous materials that would apply during the transportation of the products or materials by any mode. Similarly, in 2016, the FRA modified its accident and incident reports to gather additional data concerning rail cars carrying crude oil in any train involved in an FRA-reportable accident. In addition to these or other actions taken or proposed by federal agencies, a number of states proposed or enacted laws in recent years that encourage safer rail operations or urge the federal government to strengthen requirements for these operations.

Safety improvements or updates to existing tank cars that are imposed under PHMSA’s 2015 final rule requirements could drive up the cost of transport and lead to shortages in availability of tank cars. We do not currently own or operate rail transportation facilities or rail cars; however, we cannot assure that costs incurred by the railroad industry to comply with these enhanced standards resulting from PHMSA’s final rule will not increase our costs of doing business or limit our ability to transport and sell our crude oil at favorable prices, the consequences of which could be material to our business, financial condition or results of operations. However, we believe that any such consequences would not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Efforts are likewise underway in Canada to assess and address risks from the transport of crude oil by rail. For example, in 2014, Transport Canada issued a protective order prohibiting oil shippers from using 5,000 of the DOT-111 tank cars and imposing a three year phase out period for approximately 65,000 tank cars that do not meet certain safety requirements. Transport Canada also imposed a 50 mile per hour speed limit on trains carrying hazardous materials and required all crude oil shipments in Canada to have an emergency response plan. At the same time that PHMSA released its 2015 rule, Canada’s Minister of Transport announced Canada’s new tank car standards, which largely align with the requirements in the PHMSA rule. Likewise, Transport Canada’s rail car retrofitting and phase out timeline largely aligns with the timeline introduced under the 2015 and 2016 PHMSA rules. Transport Canada has also introduced new requirements that railways carry minimum levels of insurance depending on the quantity of crude oil or dangerous goods that they transport as well as a final report recommending additional practices for the transportation of dangerous goods. Both Transport Canada and PHMSA issued final rules in January 2018 and November 2018, respectively, that further harmonize their respective tank car standards, including with respect to tank car approvals and design requirements.

Historically, our hazardous materials transportation compliance costs have not had a material adverse effect on our results of operations; however, any new laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement regarding hazardous material transportation may occur in the future, which could directly and indirectly increase our operation, compliance and transportation costs and lead to shortages in availability of tank cars. We cannot assure that costs incurred to comply with standards and regulations emerging from these existing and any future rulemakings will not be material to our business, financial condition or results of operations. Moreover, we may incur significant constraints on transportation capacity during the period while tank cars are being retrofitted or newly constructed to comply with the new regulations. In addition, any derailment of crude oil from the Bakken shale or Delaware Basin involving crude oil that we have sold or are shipping may result in claims being brought against us that may involve significant liabilities. Although we believe that we are adequately insured against such events, we cannot assure you that our insurance policies will cover the entirety of any damages that may arise from such an event. Nonetheless, we believe that any such consequences would not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by FERC under the Natural Gas Act of 1938 (“NGA”), the Natural Gas Policy Act of 1978 (“NGPA”) and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, FERC issued a series of orders, beginning with Order No. 636, to implement its open access

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policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised FERC's pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by FERC under Order No. 637 will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission ("CFTC") and the Federal Trade Commission ("FTC"). Please see below the discussion of "Other federal laws and regulations affecting our industry—Energy Policy Act of 2005." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order No. 704, some of our operations may be required to annually report to FERC on May 1 of each year for the previous calendar year. Order No. 704 requires certain natural gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical natural gas transactions for the previous calendar year depending on the volume of natural gas transacted. Please see below the discussion of "Other federal laws and regulations affecting our industry—FERC market transparency rules."

Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities is done on a case by case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. We own and operate properties in North Dakota and Montana, which have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, both states impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

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Other federal laws and regulations affecting our industry

Energy Policy Act of 2005

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 ("EPAct 2005"). EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides FERC with the power to assess civil penalties of up to $1,269,500 per day, adjusted annually for inflation, for violations of the NGA and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,269,500 per violation per day, adjusted annually for inflation. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act, practice or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704, as described below. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

FERC market transparency rules

On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the FTC issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale from: (a) knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person; or (b) intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1,191,842 per day per violation, adjusted annually for inflation, in addition to any applicable penalty under the Federal Trade Commission Act.

Texas Railroad Commission oil and natural gas rules

The Texas Railroad Commission ("RRC"), through its Oil and Gas Division, regulates the exploration, production, and transportation of oil and natural gas in Texas. Among other duties, the RRC develops and adopts regulations to prevent waste of the state's oil and natural resources, protects the correlative rights of different interest owners, prevents pollution, and provides safety with respect to operations including, for example, hydrogen sulfide emissions. The RRC grants drilling permits based on established spacing and density rules. Additionally, each month, the RRC assigns production allowables on oil and natural gas wells based on factors such as tested well capability, reservoir mechanics, market demand for production, and past production, as well as receives operators' production reports on oil leases and gas wells, and audits the oil disposition path to ensure production did not exceed allowables. The RRC also regulates oil field injection and disposal wells under a federally-approved program that includes permitting, annual reporting and periodic testing activities. Through this program, fluids are injected into either productive reservoirs under enhanced recovery projects to increase production or into non-productive reservoirs for disposal. In other pollution prevention activities, the RRC assures waste management is carried out by permitting pits and landfarming, discharges, waste haulers, waste minimization, and hazardous waste management tasks. To prevent pollution of the state's surface and ground water resources, the RRC has an abandoned well plugging and abandoned site remediation program that uses funds provided by industry through fees and taxes. Wells and sites are remediated with funds from this program when responsible operators cannot be found.

North Dakota Industrial Commission oil and natural gas rules

The North Dakota Industrial Commission ("NDIC") regulates the drilling and production of oil and natural gas in North Dakota. Beginning in 2012, the NDIC adopted more stringent rules, imposing increased bonding amounts for the drilling of wells, severely restricting the discharge and storage of production wastes such as produced water, drilling mud, waste oil and other wastes in earthen pits, implementing more stringent hydraulic fracturing requirements and requiring the provision of public disclosure on FracFocus.org regarding chemicals used in the hydraulic fracturing process. In 2016, the NDIC approved a suite of additional rules for the conservation of crude oil and natural gas, including new requirements relating to site construction, underground gathering pipelines, spill containment bonding requirements for underground gathering pipelines, and construction of berms around facilities, which new requirements are now in effect. These requirements have increased the well costs incurred by us and similarly situated oil and natural gas E&P operators, and we expect to continue to incur these increased costs as well as any added costs arising from new NDIC legal requirements laws and regulations applicable to the drilling and production of oil and natural gas that may be issued in the future.

Furthermore, in 2014, the NDIC adopted an order intended to reduce natural gas flaring, which order was subsequently modified in late 2015 and the underlying flaring program's policy goals were revised in November 2018. Please see below the discussion of "Environmental protection and natural gas flaring initiatives" for more information on this order. In addition, in 2014, the NDIC adopted conditioning standards that are now in effect and improve the safety of Bakken crude oil for transport. Among other things, the 2014 rule sets operating standards for conditioning equipment to properly separate production fluids, addresses limits to the vapor pressure of produced crude oil, and includes parameters for temperatures and pressures associated with the production equipment.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Pipeline safety regulation

Certain of our pipelines are subject to regulation by PHMSA under the Hazardous Liquids Pipeline Safety Act ("HLPSA") with respect to oil and condensates and the Natural Gas Pipeline Safety Act ("NGPSA") with respect to natural gas. The HLPSA and NGPSA govern the design, installation, testing, construction, operation, replacement and management of oil and natural gas pipeline facilities. These laws have resulted in the adoption of rules by PHMSA, that, among other things, require transportation pipeline operators to implement integrity management programs, including more frequent inspections, correction of identified anomalies and other measures to ensure pipeline safety in high consequence areas ("HCAs"), such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. In addition, states have adopted regulations similar to existing PHMSA regulations for certain intrastate gas and hazardous liquid pipelines, which regulations may impose more stringent requirements than found under federal law. Historically, our pipeline safety compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance costs will not have a material adverse effect on our business and operating results. New pipeline safety laws or regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs and operational delays.

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Legislation in recent years has resulted in more stringent mandates for pipeline safety and has charged PHMSA with developing and adopting regulations that impose increased pipeline safety requirements on pipeline operators. The HLPSA and NGPSA were amended by the Pipeline, Safety, Regulatory Certainty and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"). The 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. In June 2016, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the "2016 Pipeline Safety Act") was passed, extending PHMSA's statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and developing new safety standards for natural gas storage facilities. The 2016 Pipeline Safety Act also empowers PHMSA to address unsafe conditions or practices constituting imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of hazardous liquid or natural gas pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in 2016 to implement the agency's expanded authority to address such conditions or practices that pose an imminent hazard to life, property or the environment.

The adoption of new or amended regulations by PHMSA that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on our results of operations. For example, in January 2017, PHMSA issued a final rule that significantly extends and expands the reach of certain PHMSA hazardous liquid pipeline integrity management requirements, such as, for example, periodic assessments, leak detection and repairs, regardless of the pipeline's proximity to a high consequence area. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, the date of implementation of this final rule by publication in the Federal Register has been delayed following the January 2017 change in presidential administrations. In a second example, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for natural gas pipelines in newly defined "moderate consequence areas" that contain as few as five dwellings within a potential impact area; requiring natural gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures ("MAOP"); and requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements for natural gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. PHMSA has split this proposed rule into three separate rulemaking proceedings and is expected to finalize those proceedings in 2019. New legislation or any new regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs and operational delays. In the absence of the PHMSA pursuing any legal requirements, state agencies, to the extent authorized, may pursue state standards, including standards for rural gathering lines.

Environmental and occupational health and safety regulation

Our exploration, development and production operations, oil gathering and transportation activities, natural gas processing services and related operations are subject to stringent federal, tribal, regional, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct drilling or provide midstream services; govern the amounts and types of substances that may be released into the environment; limit or prohibit construction or drilling activities in environmentally-sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered species; require investigatory and remedial actions to mitigate pollution conditions; impose obligations to reclaim and abandon well sites, pits, processing plants and pipelines; and impose specific criteria addressing worker protection. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations or the incurrence of capital expenditures, the occurrence of restrictions, delays or cancellations in the permitting, development or expansion of projects and the issuance of orders enjoining some or all of our operations in affected areas. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any new laws or regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement that result in more stringent and costly well construction, drilling, water management or completion activities, or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our results of operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental spills or other releases may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such spills or releases, including any third-party claims for

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damage to property, natural resources or persons. While, historically, our compliance costs with environmental laws and regulations have not had a material adverse effect on our financial position, cash flows and results of operations, there can be no assurance that such costs will not be material in the future as a result of such existing laws and regulations or any new laws and regulations, or that such future compliance will not have a material adverse effect on our business and operating results.

The following is a summary of the more significant existing environmental and occupational health and safety laws, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and wastes

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These classes of persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency ("EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. 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 or other pollutants into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We are also subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation, disposal and cleanup of hazardous and nonhazardous wastes. Under the authority of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. In the course of our operations, we generate ordinary industrial wastes that may be regulated as hazardous wastes. RCRA currently exempts certain drilling fluids, produced waters and other wastes associated with exploration, development and production of oil and natural gas from regulation as hazardous wastes. These wastes, instead, are regulated under RCRA's less stringent nonhazardous waste provisions, state laws or other federal laws. However, it is possible that certain oil and natural gas exploration, development and production wastes now classified as nonhazardous wastes could be classified as hazardous wastes in the future. For example, pursuant to a consent decree issued by a federal court, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D regulations that result in such oil and natural gas wastes being regulated as hazardous wastes, or sign a determination that revision of those RCRA regulations is unnecessary. If the EPA proposes a rulemaking for revised oil and natural gas regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Repeal or modification of the current RCRA exclusion or similar exemptions under state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us or our customers to incur increased operating costs, which could have a significant impact on us as well as reduce demand for our midstream and well services.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas or for conducting midstream services. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons, hazardous substances and wastes may have been released on, under or from the properties owned or leased by us or on, under or from, other locations where these petroleum hydrocarbons and wastes have been taken for recycling or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons, hazardous substances and wastes were not under our control. These properties and the substances disposed or released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial plugging or pit, processing plant or pipeline closure operations to prevent future contamination.

Air emissions

The federal Clean Air Act ("CAA") and comparable state laws and regulations restrict the emission of various air pollutants from many sources through air emissions standards, construction and operating permitting programs, and the imposition of other monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Obtaining permits has the potential to restrict, delay or cancel the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard (“NAAQS”) for ground-level ozone to 70 parts per billion under both the primary and secondary standards. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either “attainment/unclassifiable,” “unclassifiable” or “non-attainment.” Additionally, in November 2018, the EPA issued final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. State implementation of these revised standards could result in stricter permitting requirements, delay, limit or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Compliance with this final rule or any other new legal requirements could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, significantly increase our capital expenditures and operating costs, and reduce demand for the oil and natural gas that we produce, which one or more developments could adversely impact our production, midstream and well services businesses.

Environmental protection and natural gas flaring initiatives

We attempt to conduct our operations in a manner that protects the health, safety and welfare of the public, our employees and the environment. We are focused on the reduction of air emissions produced from our operations, particularly with respect to flaring of natural gas from our operated well sites. The rapid growth of crude oil production in North Dakota in recent years, coupled with a historical lack of natural gas gathering infrastructure in the state, has led to efforts to reduce flaring of natural gas produced in association with crude oil production. We recognize the environmental and financial risks associated with natural gas flaring, and we seek to manage these risks on an ongoing basis, consistent with applicable requirements.

We believe that one of the leading causes of natural gas flaring from the Bakken and Three Forks formations is the inability of operators to promptly connect their wells to natural gas processing and gathering infrastructure due to external factors out of the control of the operator, such as, for example, the granting of right-of-way access by land owners, investment from third parties in the development of gas gathering systems and processing facilities, and the development and adoption of regulations. However, we have allocated significant resources to connect our Bakken and Three Forks wells to natural gas infrastructure to reduce our flared volumes. We have exceeded a goal that we voluntarily set in 2014 to maintain well connections for an average of 90% of our operated Bakken and Three Forks wells, by having approximately 98% of our operated Bakken and Three Forks wells connected to gathering systems since 2015. We believe that achieving this goal helps us to minimize our flared volumes of natural gas.

In 2014, the NDIC adopted Order No. 24665 (the “2014 Order”), pursuant to which the agency adopted legally enforceable “gas capture percentage goals” targeting the capture of natural gas produced in the state between October 1, 2014 and October 1, 2020. Modification of the July 2014 Order by the NDIC in late 2015, resulted in revised gas capture percentage goals of 88% and 91% required to be achieved by November 1, 2018 and November 1, 2020, respectively. Most recently, in November 2018, the NDIC considered revising its 2018 and 2020 gas capture percentage goals but elected to retain those standards; however, the NDIC revised the flaring program’s policy goals such that the oil and gas exploration and production industry has more flexibility in removing certain gas volumes from consideration in calculating compliance with the state’s gas capture percentage goals. The NDIC continues to adhere to other aspects of the modified 2014 Order, including development of Gas Capture Plans that provide measures for reducing the amount of natural gas flared by those operators so as to be consistent with the agency’s gas capture percentage goals. Also, wells must continue to meet or exceed the NDIC’s gas capture percentage goals on a statewide, county, per-field, or per-well basis. If an operator is unable to attain the applicable gas capture percentage goal at maximum efficiency rate, wells will be restricted in production to 200 barrels of oil per day if at least 60% of the monthly volume of associated natural gas produced from the well is captured, or otherwise oil production from such wells shall not exceed 100 barrels of oil per day. However, the NDIC will consider flexibility to these production restrictions, by means of temporary exemptions, for other types of extenuating circumstances after notice and hearing if the effect of such flexibility is a significant net increase in gas capture within one year of the date such relief is granted. Monetary penalty provisions also apply under this policy in the event an operator not meeting the gas capture percentage goals fails to timely file for a hearing with the NDIC upon being unable to meet such percentage goals or if the operator fails to timely implement production restrictions once below the applicable percentage goals. As of December 31, 2018, we were capturing approximately 88% of our natural gas production in North Dakota. While we were satisfying the applicable gas capture percentage goals as of December 31, 2018 and expect to satisfy the November 1, 2020 gas capture percentage goals of 91%, there is no assurance that we will remain in compliance in the future or that such future satisfaction of such goals will not have a material adverse effect on our business and results of operations.

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Climate change

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of greenhouse gases ("GHGs"). These efforts have included consideration by states or groupings of states of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment and has adopted regulations under existing provisions of the CAA that establish Prevention of Significant Deterioration ("PSD") construction under Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including, among others, onshore and offshore oil and natural gas production facilities and onshore processing, transmission, storage and distribution facilities, which include certain of our operations. The EPA has amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In 2016, the EPA published New Source Performance Standards ("NSPS"), known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards expand the previously issued NSPS Subpart OOOO requirements issued in 2012 by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. In June 2017, the EPA published a proposed rule to stay certain portions of the 2016 standards for two years but the rule was not finalized. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule, and in September 2018 the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency. Furthermore, in November 2016, the Bureau of Land Management ("BLM") published a final rule to reduce methane emissions by regulating venting, flaring, and leaking from oil and natural gas operations on public lands. However, in September 2018, the BLM published a final rule that rescinds most of the new requirements of the November 2016 final rule and codifies the BLM's prior approach to venting and flaring, but the rule rescinding the November 2016 final rule has been challenged in federal court and remains pending. Internationally, in April 2016, the United States joined other countries in entering into a United Nations-sponsored non-binding agreement in Paris, France ("Paris Agreement") for nations to limit their GHG emissions through individually-determined reduction goals every five years beginning in 2020. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement, which provides for a four-year exit process beginning when the agreement took effect in November 2016.

The adoption and implementation of any international, federal or state legislation, regulations or other regulatory initiatives that require reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur increased costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory or reporting requirements, including the imposition of a carbon tax, which one or more developments could have an adverse effect on our business, financial condition and results of operations. Moreover, such new legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for oil and gas, which could reduce the demand for the oil and natural gas we or our customers produce and lower the value of our reserves as well as reduce demand for our midstream and well services. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040 and other studies by the private sector project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities.

Finally, it should be noted 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 storms, floods and other climatic events. If such effects were to occur, our development and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities because of climate related damages to our facilities, our costs of operations potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by such climate effects, or increased costs for insurance coverage in the aftermath of such effects. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

Water discharges

The Federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In 2015, the EPA and U.S. Army Corps of Engineers ("Corps") issued a final rule outlining their position on the federal jurisdictional reach over waters of the United States. The rule has been challenged in federal district court on the grounds that it unlawfully expands the reach of Clean Water Act programs, and implementation of the rule has been enjoined in twenty-eight states, including North Dakota, Montana and Texas, where we conduct operations, pending resolution of the legal challenges. In July 2017, the EPA and the Corps published a proposed rule to rescind the 2015 rule and, in February 2018, the agencies published a final rule adding a February 6, 2020 applicable date to the 2015 rule. The February 2018 rule extending the 2015 final rule's date of applicability is currently subject to litigation. Also, in December 2018, the EPA and the Corps published a proposed rule defining the Clean Water Act's jurisdiction, for which agencies will seek public comment. As a result of these developments, future implementation of the rule is uncertain at this time. To the extent this rule expands the scope of the Clean Water Act's jurisdiction, drilling programs could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The Oil Pollution Act of 1990 ("OPA") amends the Clean Water Act and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities and onshore facilities, including E&P facilities that may affect waters of the United States. Under the OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Operations associated with our production and development activities generate drilling muds, produced waters and other waste streams, some of which may be disposed of by means of injection into underground wells situated in non-producing subsurface formations. These injection wells are regulated pursuant to the federal Safe Drinking Water Act ("SDWA") Underground Injection Control ("UIC") program and analogous state laws. The UIC program requires permits from the EPA or analogous state agency for disposal wells that we operate, establishes minimum standards for injection well operations and restricts the types and quantities of fluids that may be injected. Any leakage from the subsurface portions of the injection wells may cause degradation of fresh water, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages and personal injuries. Moreover, any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and ultimately increase the cost of our operations, which costs could be significant. Furthermore, in response to recent seismic events near underground injection wells used for the disposal of produced water from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity. In 2016, the United States Geological Survey identified Texas as being among the states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in Texas, the Texas Railroad Commission has adopted rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us or our customers. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in operational activities, our or our customers' costs to operate may significantly increase and our or our customers' ability to continue production or conduct midstream services or dispose of produced water may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

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Hydraulic fracturing activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from unconventional formations, including shales. The process involves the injection of water, sand or other proppants and chemical additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs.

The hydraulic fracturing process is typically regulated by state oil and natural gas commissions or similar agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has asserted regulatory authority pursuant to the SDWA's UIC program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities, as well as published an ANPR regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. The EPA also issued final CAA regulations in 2012 and 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing or from compressors, controls, dehydrators, storage tanks, natural gas processing plants, and certain other equipment. In addition, in 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. Also, the BLM published a final rule in 2015 establishing new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands, but the BLM rescinded the 2015 rule in December 2017; however, litigation challenging the BLM's decision was filed in federal District Court in January 2018 and remains pending.

From time to time Congress has considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, some states, including North Dakota and Texas where we primarily operate, have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. States could elect to prohibit high-volume hydraulic fracturing altogether, following the approach taken by the State of New York. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Nevertheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities and perhaps even be precluded from drilling wells.

Additionally, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to, and litigation concerning, oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to added delays, restrictions or cancellations in the pursuit of our operations or increased operating costs in our or our customers' production of oil and natural gas. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and natural gas wells, which could have a material adverse effect on our business or results of operations with respect to E&P activities and midstream services. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.

Endangered Species Act considerations

The federal Endangered Species Act ("ESA") and comparable state laws may restrict exploration, development and production activities that may affect endangered and threatened species or their habitats. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States and prohibits the taking of endangered species. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed or endangered species or modify their critical habitats. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. If endangered or threatened species are located in areas of the underlying properties where we or our customers wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed by seasonal or permanent restrictions or require the implementation of expensive mitigation. Moreover, as a result of one or more settlements entered into by the U.S. Fish and Wildlife Service, the agency is required to make determinations on the listing of numerous species as endangered or threatened under the ESA pursuant to specific timelines. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted or planned could cause us or our customers to incur increased costs arising from species protection measures or could result in delays or limitations on our or our customers' E&P activities, including the performance of drilling programs that could have an adverse impact on our ability to develop and produce reserves or an indirect adverse impact on the demand for our midstream services.

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Operations on federal lands

Performance of oil and natural gas E&P activities on federal lands, including Indian lands and lands administered by the federal BLM are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the BLM and the federal Bureau of Indian Affairs, to evaluate major agency actions, such as the issuance of permits that have 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. Depending on any mitigation strategies recommended in such environmental assessments or environmental impact statements, we could incur added costs, which could be substantial, and be subject to delays, limitations or prohibitions in the scope of oil and natural gas projects or performance of midstream services. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt our or our customers' E&P activities.

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the U.S. Occupational Safety and Health Administration ("OSHA") hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state regulations require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Employees

As of December 31, 2018, we employed 727 people. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Offices

As of December 31, 2018, we lease 130,300 square feet of office space in Houston, Texas at 1001 Fannin Street, where our principal offices are located, and sub-lease 8,820 square feet and 7,800 square feet of office space in Houston, Texas, and Midland, Texas, respectively. The lease for our Houston office expires in March 2029 and our sub-leases for our Houston and Midland offices expire in December 2019 and August 2020, respectively. We also own field offices in the North Dakota communities of Williston, Powers Lake, Alexander and Watford City.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. Our filings with the SEC are available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange ("NYSE") under the symbol "OAS." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://www.oasispetroleum.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K.

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Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition, results of operations or cash flows could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks related to the oil and natural gas industry and our business

A substantial or extended decline in commodity prices, in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas, heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. For example, average daily prices for WTI crude oil ranged from a high of $76.41 per barrel to a low of $42.53 per barrel during 2018. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $6.24 per MMBtu to a low of $2.49 per MMBtu during 2018. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America, China, India and Russia;
- the level of global oil and natural gas E&P activities;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and regional, domestic and international transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations and policies, including environmental requirements;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- stockholder activism or activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and natural gas and related infrastructure;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than twelve-month) contracts at market-based prices. Low oil and natural gas prices will reduce our cash flows, borrowing ability, the present value of our reserves and our ability to develop future reserves. See "Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our estimated net oil and natural gas reserves" below. Low oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically and may affect our proved reserves. See also "The present value of future net revenues from our estimated net proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves" below.

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Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned operating results.

We may not be able to generate enough cash flows to meet our debt obligations.

We expect our earnings and cash flows to vary significantly from year to year due to the nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flows may be insufficient to meet our debt obligations and other commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flows from operations and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control. If we do not generate enough cash flows from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- refinancing or restructuring our debt.

If for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements. In addition, our lenders could compel us to apply all of our available cash to repay our borrowings or they could prevent us from making payments on our Notes (as defined in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources"). If amounts outstanding under our Revolving Credit Facilities or our Notes were to be accelerated, we cannot be certain that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Our Revolving Credit Facilities and the indentures governing our Senior Notes all contain operating and financial restrictions that may restrict our business and financing activities.

Our Revolving Credit Facilities and the indentures governing our Senior Notes (as defined in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources") contain a number of restrictive covenants that impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;
- pay distributions on, redeem or repurchase our common stock or redeem or repurchase our debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create or incur certain liens;
- make certain acquisitions and investments;
- redeem or prepay other debt;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;

- create unrestricted subsidiaries;
- enter into sale and leaseback transactions; and

- engage in certain business activities.

As a result of these covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the covenants and restrictions contained in our Revolving Credit Facilities and the indentures governing our Senior Notes may be affected by events beyond our control. If market or other economic conditions deteriorate or if oil and natural gas prices decline substantially or for an extended period of time from their current levels, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our Revolving Credit Facilities, the indentures governing our Senior Notes or any future indebtedness could result in an event of default under our Revolving Credit Facilities, the indentures governing our Senior Notes or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations.

If an event of default under either of our Revolving Credit Facilities occurs and remains uncured, the lenders under the applicable Revolving Credit Facility:

- would not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- may have the ability to require us to apply all of our available cash to repay these borrowings; or
- may prevent us from making debt service payments under our other agreements.

A payment default or an acceleration under our Revolving Credit Facilities could result in an event of default and an acceleration under the indentures for our Notes. If the indebtedness under the Notes were to be accelerated, there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness in full. In addition, our obligations under the Oasis Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 90% of the reserve value as determined by reserve reports, and if we are unable to repay our indebtedness under the Oasis Credit Facility, the lenders could seek to foreclose on our assets. Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources.”

Our level of indebtedness may increase and reduce our financial flexibility.

As of December 31, 2018, we had $468.0 million of outstanding borrowings and had $14.0 million of outstanding letters of credit under the Oasis Credit Facility, $318.0 million of outstanding borrowings under the OMP Credit Facility, $950.0 million available for future secured borrowings under the Revolving Credit Facilities and $2,039.4 million outstanding in Notes. Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Senior secured revolving line of credit,” “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Senior unsecured notes” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Senior unsecured convertible notes.” In the future, we may incur significant indebtedness in order to make future acquisitions or to develop our properties.

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

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- a high level of debt may 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; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. If oil and natural gas prices decline substantially or for an extended period of time from their current levels, we may not be able to generate sufficient cash flows to pay the interest on our debt and future working capital, and borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

In addition, our bank borrowing base is subject to periodic redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative arrangements for a portion of our oil and natural gas production, including collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual price received.

In addition, some of these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

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

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas E&P activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "Our estimated net proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves" below. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. These levels of uncertainty may be increased with respect to our recently acquired positions in the Delaware Basin due to our inexperience operating in the area. See "The Permian Basin Acquisition represents our initial expansion outside of the Williston Basin, and we may not be successful in operating in other geographic regions" below. Overruns in planned expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions and/or failure;
- unexpected operational events, including accidents;
- pressure or irregularities in geological formations;

- adverse weather conditions, such as blizzards, ice storms and floods;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;

- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. See “Item 1. Business—Our operations - exploration and production activities” for information about our estimated oil and natural gas reserves and the PV-10 and Standardized Measure of discounted future net revenues as of December 31, 2018, 2017 and 2016.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Although the reserve information contained herein is reviewed by our independent reserve engineers, estimates of oil and natural gas reserves are 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 will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. In addition, we may adjust estimates of net proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Due to the limited production history of our undeveloped acreage, the estimates of future production associated with such properties may be subject to greater variance to actual production than would be the case with properties having a longer production history.

The present value of future net revenues from our estimated net proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our estimated net proved reserves is the current market value of our estimated net oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2018, 2017 and 2016, we based the estimated discounted future net revenues from our estimated net proved reserves on the twelve-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

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

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from estimated net proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this Annual Report on Form 10-K. Any significant future price changes will have a material effect on the quantity and present value of our estimated net proved reserves.

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If oil and natural gas prices decline substantially or for an extended period of time from their current levels, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. In addition, we assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties, which may result in a decrease in the amount available under our Revolving Credit Facilities. A write-down constitutes a non-cash charge to earnings. A substantial or extended decline in oil and natural gas prices may cause us to incur impairment charges in the future, which could have a material adverse effect on our ability to borrow under our Revolving Credit Facilities and our results of operations for the periods in which such charges are taken. Due to the volatility of expected future oil prices, we reviewed our proved oil and natural gas properties for impairment as of December 31, 2018, 2017 and 2016. During the year ended December 31, 2018, we recorded an impairment loss of $383.4 million to adjust the carrying value of certain non-strategic proved and unproved oil and natural gas properties held for sale to their estimated fair value, determined based on the expected sales price less costs to sell. For the year ended December 31, 2017, no impairment was recorded on our proved oil and natural gas properties. During the year ended December 31, 2016, we recorded impairment losses of $1.1 million to adjust the carrying values of our proved oil and natural gas properties held for sale to their estimated fair values. During the years ended December 31, 2018, 2017 and 2016, we recorded non-cash impairment charges of $0.9 million, $6.9 million and $1.1 million, respectively, on our unproved properties due to expiring leases and periodic assessments of our unproved properties.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services or the unavailability of sufficient transportation for our production could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs of rigs, equipment, supplies and personnel are substantially greater and their availability to us may be limited. Additionally, these services may not be available on commercially reasonable terms. Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services or the unavailability of sufficient transportation for our production could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital plan, which could have a material adverse effect on our business, financial condition or results of operations. Additionally, compliance with new or emerging legal requirements that affect midstream operations in North Dakota may reduce the availability of transportation for our production. For example, the NDIC adopted regulations in late 2013 that impose more rigorous pipeline development standards on midstream operators, some of whom we rely on to construct and operate pipeline infrastructure to transport the oil and natural gas we produce.

Part of our strategic tactics involve drilling in existing or emerging shale plays using some of the latest available horizontal drilling and completion techniques. The results of our planned drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production. As a result, we may incur material write-downs and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations, successfully cleaning out the well bore after completion of the final fracture stimulation stage and successfully protecting nearby producing wells from the impact of fracture stimulation.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, and/or oil and natural gas prices decline, the return on our investment in these areas may not be as attractive as we anticipate. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future.

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Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our estimated net oil and natural gas reserves.

Our exploration and development activities are capital intensive. 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. Excluding acquisitions of $951.9 million in 2018 and $54.0 million in 2017, we spent $1,251.6 million and $782.2 million related to capital expenditures for the years ended December 31, 2018 and 2017, respectively. Our total capital expenditure plan for 2019 is approximately $690 million to $730 million, which includes approximately $540 million to $560 million for E&P and other capital expenditures, including approximately $405 million to $420 million focused in the Williston Basin and approximately $135 million to $140 million focused in the Delaware Basin (with approximately 85% of the E&P capital allocated to drilling and completions). Other capital expenditures includes OWS and administrative capital, and excludes capitalized interest of approximately $15 million. Since our initial public offering, our capital expenditures have been financed with proceeds from public equity offerings, proceeds from our issuance of senior notes, borrowings under our Revolving Credit Facilities, net cash provided by operating activities, the sale of non-strategic oil and gas properties and cash settlements of derivative contracts. DeGolyer and MacNaughton projects that we will incur capital costs of $1,592.0 million over the next five years to develop the proved undeveloped reserves in the Williston Basin and Delaware Basin covered by its December 31, 2018 reserve report. 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, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

A significant increase in product prices could result in an increase in our capital expenditures. We intend to finance our future capital expenditures primarily through cash flows provided by operating activities, borrowings under our Revolving Credit Facilities and cash settlements of derivative contracts; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of additional debt or equity securities or the sale of non-strategic assets. The issuance of additional debt or equity may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under the Oasis Credit Facility will be automatically reduced by an amount equal to 25% of the aggregate principal amount of such debt securities.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our estimated net proved reserves;
- the level of oil and natural gas we are able to produce from existing wells and new projected wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas production;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

If the borrowing base under our Revolving Credit Facilities or our revenues decrease as a result of low 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 Revolving Credit Facilities 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.

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We will not be the operator on all of our drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets.

We may enter into arrangements with respect to existing or future drilling locations that result in a greater proportion of our locations being operated by others. As a result, we may have limited ability to exercise influence over the operations of the drilling locations operated by our partners. Dependence on the operator could prevent us from realizing our target returns for those locations. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

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

This limited ability to exercise control over the operations of some of our drilling locations may cause a material adverse effect on our results of operations and financial condition.

All of our producing properties and operations are located in the Williston Basin and Delaware Basin regions, making us vulnerable to risks associated with operating among a limited number of geographic areas.

As of December 31, 2018, 87% and 95% of our proved reserves and production, respectively, were located in the Williston Basin in northwestern North Dakota and northeastern Montana and the remaining 13% and 5% of our proved reserves and production, respectively, were located in the Delaware Basin in west Texas. As a result, we may be disproportionately exposed to the impact of economics in the Williston Basin and Delaware Basin or delays or interruptions of production from those wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in those areas. 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 Williston Basin and Delaware Basin, which may cause these conditions to occur with greater frequency or magnify the effect 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.

The Permian Basin Acquisition represents our initial expansion outside of the Williston Basin, and we may not be successful in operating in other geographic regions.

Our operations have historically focused on a single geographic region, namely the North Dakota and Montana regions of the Williston Basin. Thus, the Permian Basin Acquisition represents our initial entry into the Delaware Basin, and our first expansion of our operations outside of the Williston Basin. Certain aspects related to operating in the Delaware Basin may not be as familiar to us as our existing project areas. As a result, we may encounter obstacles that may cause us not to achieve the expected results of the Permian Basin Acquisition. These obstacles may include a less familiar geological landscape, different completion techniques, midstream and downstream operators with whom we have no established relationship, greater competition for acreage, unfamiliar operating conditions and a distinct regulatory environment. Any adverse conditions, regulations or developments related to our expansion into the Delaware Basin may have a negative impact on our business, financial condition and results of operations.

Our business depends on oil and natural gas gathering and transportation facilities, some of which are owned by third parties.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties and by OMP. The unavailability of, or lack of, available capacity on these systems and facilities could result in the shut-in of producing wells or the delay, or discontinuance of, development plans for properties. See also "Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production" and "Insufficient transportation, end-market refining utilization or natural gas processing capacity in the Williston Basin and Delaware Basin could cause significant fluctuations in our realized oil and natural gas prices” below. The transportation of our production can be interrupted by other customers that have firm arrangements. In addition, these third parties may also impose specifications for the products that they are willing to accept. If the total mix of a product fails to meet the applicable product quality specifications, the third parties may refuse to accept all or a part of the products or may invoice us for the costs to handle or damages from receiving the out-of-specification products. In those circumstances, we may be required to delay the delivery of or find alternative markets for that product, or shut-in the producing wells that are causing the products to be out of specification, potentially reducing our revenues.

The disruption of third-party facilities due to maintenance, weather or other interruptions of service could also negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored. A total shut-in of our production could materially affect us due to a resulting lack of cash flows, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flows. Potential crude oil train derailments or crashes could also impact our ability to market and deliver our products and cause significant fluctuations in our realized oil and natural gas prices due to tighter safety regulations imposed on crude-by-rail transportation and interruptions in service.

Insufficient transportation, end-market refining utilization or natural gas processing capacity in the Williston Basin and Delaware Basin could cause significant fluctuations in our realized oil and natural gas prices.

The crude oil business environment has historically been characterized by periods when oil production has surpassed local transportation and refining capacity, resulting in substantial discounts in the price received for crude oil versus prices quoted for WTI crude oil. In the past, there have been periods when this discount has substantially increased due to the production of oil in the area increasing to a point that it temporarily surpasses the available pipeline transportation, rail transportation and refining capacity in the area. Expansions of both rail and pipeline facilities have reduced the prior constraint on oil transportation out of the Williston Basin and Delaware Basin and improved netback pricing received at the lease. On barrels that we transport and sell outside of the basins, our realized price for crude oil is generally the quoted price at the point of sale less transportation costs. In 2017 and the majority of 2018, our Williston Basin price differentials relative to WTI strengthened as new pipelines opened to eastern Canada and U.S. markets and transportation on rail gradually declined. In the fourth quarter of 2018, Williston Basin differentials weakened as overall basin production grew faster than forecasted. Since 2016, our Williston Basin price differentials have averaged less than $5.00 per barrel discount to WTI on a quarterly basis. During 2017 and throughout most of 2018, our Williston Basin crude oil price differentials improved to less than $2.00 per barrel discount to WTI primarily due to the additional takeaway capacity of the Dakota Access Pipeline of over 500,000 barrels per day. In 2018, our Delaware Basin price differentials relative to WTI weakened due to transportation capacity restraints, averaging more than $4.00 per barrel below WTI.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. If our production becomes shut-in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

The development of our proved undeveloped reserves in the Williston Basin, Delaware Basin and other areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 37% of our estimated net proved reserves were classified as proved undeveloped as of December 31, 2018. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecasts as well as access to liquidity sources, such as capital markets, our Revolving Credit Facilities and derivative contracts. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

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Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our estimated net proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flows and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas E&P activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as natural gas leaks, oil and produced water spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials and unauthorized discharges of brine, well stimulation and completion fluids, toxic gas or other pollutants into the environment;
- abnormally pressured formations;
- shortages of, or delays in, obtaining water for hydraulic fracturing activities;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing failure;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

Insurance against all operational risk is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Also, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

We have incurred losses in 2018 and prior years and may do so again in the future.

For the year ended December 31, 2018, we incurred a net loss of $35.3 million. For the year ended December 31, 2017, we incurred a pre-tax loss of $75.9 million, but had a positive net income after taxes primarily due to the income tax benefit related to the tax rate change under the Tax Act. For the year ended December 31, 2016, we incurred a net loss of $243.0 million. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures, including planned capital expenditures for 2019 of approximately $690 million to $730 million.

The uncertainty and risks described in this Annual Report on Form 10-K may impede our ability to economically find, develop, exploit and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by operating activities in the future.

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Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Williston Basin and Delaware Basin may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our potential drilling location inventories are scheduled to be drilled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our execution strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. These levels of uncertainty may be increased with respect to our recently acquired positions in the Delaware Basin due to our inexperience operating in the area. See “The Permian Basin Acquisition represents our initial expansion outside of the Williston Basin, and we may not be successful in operating in other geographic regions” above. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage, the primary term is extended through continuous drilling provisions or the leases are renewed. In the highly competitive market for acreage, failure to drill sufficient wells in order to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

As of December 31, 2018, approximately 97% and 67% of our total net acreage in the Williston Basin and Delaware Basin, respectively, was held by production. The leases for our net acreage not held by production will expire at the end of their primary term unless production is established in paying quantities under the units containing these leases, the leases are held beyond their primary terms under continuous drilling provisions or the leases are renewed. In the Williston Basin, our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. In the Delaware Basin, our acreage must be drilled before lease or term assignment expiration and, in some leases, must be further perpetuated via additional drilling activity to satisfy continuous drilling and development provisions. Additionally, certain leases and term assignments in the Delaware Basin require development at various depths in order to perpetuate our ownership as to those depths. As of December 31, 2018, we had leases representing 2,720 net acres expiring in 2019, 8,992 net acres expiring in 2020 and 2,456 net acres expiring in 2021 in the Williston Basin and Delaware Basin. The cost to renew such leases may increase significantly and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business. During the years ended December 31, 2018, 2017 and 2016, we recorded non-cash impairment charges of $0.9 million, $6.9 million and $1.1 million on our unproved properties due to expiring leases and periodic assessments of our unproved properties.

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Our operations are subject to environmental and occupational health and safety laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas E&P operations, oil gathering and transportation activities, natural gas processing services, well servicing operations and related operations are subject to stringent federal, tribal, regional, state and local laws and regulations governing occupational health and safety aspects, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations and services including the acquisition of a permit before conducting drilling, providing midstream services or other regulated activities; the restriction on types, quantities and concentration of materials that may be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and OSHA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, which may cause us to incur significant capital or operating expenditures or costly actions to achieve and maintain compliance. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties; the imposition of investigatory, remedial or corrective action obligations or the incurrence of capital expenditures; the occurrence of restrictions, delays or cancellations in the permitting or development or expansion of projects; and the issuance of injunctions limiting or preventing some or all of our operations in affected areas.

Our operations risk incurring significant environmental costs and liabilities as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and waste water discharges related to our operations and due to historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to joint and several, strict liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled or processing facilities or pipelines are located and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damage. In addition, accidental spills or other releases could expose us to significant costs and liabilities that could have a material adverse effect on our financial condition or results of operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in delayed, restricted or more stringent or costly well drilling, plant or pipeline construction, completion or water management activities or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. For example, pursuant to a consent decree issued by a federal district court, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D regulations that could result in such oil and natural gas wastes being regulated as hazardous wastes, or sign a determination that revision of those RCRA regulations is unnecessary. Also, in 2015, the EPA issued a final rule lowering the NAAQS for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either “attainment/unclassifiable,” “unclassifiable” or “non-attainment” and, in November 2018, issued final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS. State implementation of these revised NAAQS standards could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Compliance with any of these rules or any other new or amended legal requirements could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

We may not be able to recover some or any of these costs from insurance.

Failure to comply with federal, state and local laws could adversely affect our ability to produce, gather and transport our oil and natural gas and may result in substantial penalties.

Our operations are substantially affected by federal, state and local laws and regulations, particularly as they relate to the regulation of oil and natural gas production and transportation. These laws and regulations include regulation of oil and natural gas E&P and related operations, including a variety of activities related to the drilling of wells, and the interstate transportation of oil and natural gas by federal agencies such as FERC, as well as state agencies. We may incur substantial costs in order to maintain compliance with these laws and regulations. As well as recent incidents involving the release of oil and natural gas and fluids as a result of drilling activities in the United States, there have been a variety of regulatory initiatives at the federal and state levels to restrict oil and natural gas drilling operations in certain locations. Any increased regulation or suspension of oil and natural gas exploration and production, or revision or reinterpretation of existing laws and regulations, that arises out of these incidents or otherwise could result in delays and higher operating costs. Such costs or significant delays could have a material adverse effect on our business, financial condition and results of operations. We must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent we are a shipper on interstate pipelines, we must comply with the FERC-approved tariffs of such pipelines and with federal policies related to the use of interstate capacity.

Should we fail to comply with all applicable statutes, rules, regulations and orders of FERC, the CFTC or the FTC, we could be subject to substantial penalties and fines.

In addition, federal laws prohibit market manipulation in connection with the purchase or sale of oil and/or natural gas. Failure to comply with federal, state and local laws could adversely affect our ability to produce, gather and transport our oil and natural gas and may result in substantial penalties. Please see "Item 1. Business—Other federal laws and regulations affecting our industry."

Our business involves the selling and shipping by rail of crude oil, including from the Bakken shale and the Delaware Basin, which involves risks of derailment, accidents and liabilities associated with cleanup and damages, as well as potential regulatory changes that may adversely impact our business, financial condition or results of operations.

A portion of our crude oil production is transported to market centers by rail. Past derailments in North America of trains transporting crude oil have caused various regulatory agencies and industry organizations, as well as federal, state and municipal governments, to focus attention on transportation by rail of flammable materials. Transportation safety regulators in the United States and Canada are concerned that crude oil from the Bakken shale may be more flammable than crude oil from other producing regions and are investigating that issue and are also considering changes to existing regulations to address those possible risks. In 2015, PHMSA adopted a final rule that includes, among other things, additional requirements to enhance tank car standards for certain trains carrying crude oil and ethanol, a classification and testing program for crude oil, and a requirement that older DOT-111 tank cars be phased out by as early as January 1, 2018 if they are not already retrofitted to comply with new tank car design standards. The rule also includes a new braking standard for certain trains, designates new operational protocols for trains transporting large volumes of flammable liquids, such as routing analyses, speed restrictions and information for local government agencies, and provides new sampling and testing requirements to improve classification of energy products placed into transport; however, in September 2018, PHMSA published a final rule that removed requirements for the new braking standard established under its 2015 final rule.

In 2016, PHMSA released a final rule mandating a phase-out schedule for all DOT-111 tank cars used to transport Class 3 flammable liquids, including crude oil and ethanol, between 2018 and 2029. Additionally, in 2016, PHMSA proposed a new rule, which has not been finalized, that would expand the applicability of comprehensive oil spill response plans so that any railroad that transports a single train carrying 20 or more loaded tanks of liquid petroleum oil in a continuous block or a single train carrying 35 or more loaded tank cars of liquid petroleum oil throughout the train must have a current, comprehensive, written plan. Also, in response to a petition from the New York Attorney General, PHMSA issued an ANPR in early 2017 stating that it was considering revising the Hazardous Materials Regulations to establish vapor pressure limits for unrefined petroleum-based products and potentially all Class 3 flammable liquid hazardous materials that would apply during the transportation of the products or materials by any mode. PHMSA has not yet issued a final version of the rule. Similarly, in February 2016, the FRA modified its accident and incident reports to gather additional data concerning rail cars carrying crude oil in any train involved in a FRA-reportable accident. In addition to these or other actions taken or proposed by federal agencies, a number of states proposed or enacted laws in recent years that encourage safer rail operations or urge the federal government to strengthen requirements for these operations.

Efforts are likewise underway in Canada to assess and address risks from the transport of crude oil by rail. For example, in 2014, Transport Canada issued a protective order prohibiting oil shippers from using 5,000 of the DOT-111 tank cars and imposing a three year phase out period for approximately 65,000 tank cars that do not meet certain safety requirements. Transport Canada also imposed a 50 mile per hour speed limit on trains carrying hazardous materials and required all crude oil shipments in Canada to have an emergency response plan. At the same time that PHMSA released its 2015 rule, Canada's Minister of Transport announced Canada's new tank car standards, which largely align with the requirements in the PHMSA rule. Likewise, Transport Canada's rail car retrofitting and phase out timeline largely aligns with the timeline introduced under the 2015 and 2016 PHMSA rules. Transport Canada has also introduced new requirements that railways carry minimum levels of insurance depending on the quantity of crude oil or dangerous goods that they transport as well as a final report recommending additional practices for the transportation of dangerous goods. Both Transport Canada and PHMSA issued final rules in January 2018 and November 2018, respectively, that further harmonize their respective tank car standards, including with respect to tank car approvals and design requirements.

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New laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement regarding hazardous material transportation may occur in the future, which could directly and indirectly increase our operation, compliance and transportation costs and lead to shortages in availability of tank cars. We cannot assure that costs incurred to comply with standards and regulations emerging from these existing and any future rulemakings will not be material to our business, financial condition or results of operations. Moreover, we may incur significant constraints on transportation capacity during the period while tank cars are being retrofitted or newly constructed to comply with the new regulations. In addition, any derailment of crude oil from the Bakken shale or Delaware Basin involving crude oil that we have sold or are shipping may result in claims being brought against us that may involve significant liabilities. Although we believe that we are adequately insured against such events, we cannot assure you that our insurance policies will cover the entirety of any damages that may arise from such events.

Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration by states or groupings of states of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has determined that emissions of GHGs present an endangerment to public health and the environment and has adopted regulations under existing provisions of the CAA that establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including, among others, certain onshore and offshore oil and natural gas production facilities, and onshore processing, transmission, storage and distribution facilities, which includes certain of our operations. The EPA has amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In 2016, the EPA published NSPS, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards expand the previously issued Subpart OOOO requirements issued in 2012 by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. In June 2017, the EPA published a proposed rule to stay certain portions of the 2016 standards for two years but the rule was not finalized. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule, and in September 2018 the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring and leaking from oil and natural gas operations on public, federal and Indian lands. However, in September 2018, the BLM published a final rule that rescinds most of the new requirements of the November 2016 final rule and codifies the BLM’s prior approach to venting and flaring, but the rule rescinding the November 2016 final rule has been challenged in federal court and remains pending. Internationally, in April 2016, the United States joined other countries in entering into the Paris Agreement for nations to limit their GHG emissions through individually-determined reduction goals every five years beginning in 2020. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement, which provides for a four-year exit process beginning when the agreement took effect in November 2016.

The adoption and implementation of any international, federal or state legislation, regulations or other regulatory initiatives imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur increased costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory or reporting requirements, including the imposition of a carbon tax, which one or more developments could have an adverse effect on our or our customers' business, financial condition and results of operations. Moreover, such new legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for oil and gas, which could reduce the demand for the oil and natural gas we or our customer produce and lower the value of our reserves as well as reduce demand for our midstream and well services. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040 and other studies by the private sector project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Ultimately, this could make it more difficult to secure funding for exploration and production, midstream activities or well services.

Finally, it should be noted 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 storms, floods and other climatic events. If such effects were to occur, our development and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities because of climate related damages to our facilities, our costs of operations potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by such climate effects, or increased costs for insurance coverage in the aftermath of such effects. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

Federal or state legislative and regulatory initiatives related to induced seismicity could result in operating restrictions or delays that could adversely affect the drilling program's production of oil and natural gas.

Operations associated with our production and development activities generate drilling muds, produced waters and other waste streams, some of which may be disposed of by means of injection into underground wells situated in non-producing subsurface formations. These injection wells are regulated pursuant to the UIC program established under the SDWA. In response to recent seismic events near underground injection wells used for the disposal of produced water from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have restricted, suspended or shut down the use of such injection wells. In March 2016, the United States Geological Survey identified Texas as being among the states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in Texas, the Texas Railroad Commission has adopted rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us or our customers. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in operational activities, our or our customers' costs to operate may significantly increase and our ability to continue production or conduct midstream services or dispose of produced water may be delayed or limited, which could have a material adverse effect on our business, financial condition and results of operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand or other proppant and chemical additives under pressure into the targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs.

The process is typically regulated by state oil and natural gas commissions or similar agencies, but several federal agencies have asserted regulatory authority or conducted investigations over certain aspects of the process. For example, the EPA has asserted regulatory authority under the SDWA over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities, as well as published an ANPR regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing; issued final CAA regulations that include NSPS for completions of hydraulically fractured natural gas wells and new emissions standards for methane from certain new, modified and reconstructed equipment and processes in the oil and natural gas source category; and published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. Also, in 2015, the BLM published a final rule establishing new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands, but the BLM rescinded the 2015 rule in December 2017. However, litigation challenging the BLM’s decision was filed in federal district court in January 2018 and remains pending. Also, in late 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.

In addition, from time to time Congress has considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including North Dakota and Texas where we primarily operate, have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to, and litigation concerning, oil and natural gas production activities using hydraulic fracturing techniques. Also, new or more stringent legislation or regulation adopted in areas where we operate could also lead to delays in, or restriction or cancellation of, our or our customers’ operations, result in increased operating costs in our or our customers’ production of oil and natural gas, and perhaps cause a decrease in the completion of new oil and natural gas wells, which could have a material adverse effect on our business or results of operations with respect to E&P activities and midstream and well services. We may not be insured for, or our insurance may be inadequate to protect us against, these risks.

Operations using hydraulic fracturing are substantially dependent on the availability of water. Restrictions on the ability to obtain water for E&P activities and the disposal of flowback and produced water may impact operations and have a corresponding adverse effect on our business, financial conditions and results of operations.

Water is an essential component of shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Our access to water to be used in these processes may be adversely affected due to reasons such as periods of extended drought, private, third party competition for water in localized areas or the implementation of local or state governmental programs to monitor or restrict the beneficial use of water subject to their jurisdiction for hydraulic fracturing to assure adequate local water supplies. The occurrence of these or similar developments may result in limitations being placed on allocations of water due to needs by third party businesses with more senior contractual or permitting rights to the water. Our inability to locate or contractually acquire and sustain the receipt of sufficient amounts of water could adversely impact our E&P operations or midstream and well services and have a corresponding adverse effect on our business, financial condition and results of operations.

Moreover, the imposition of new environmental regulations and other regulatory initiatives could include increased restrictions on our or our customers’ ability to dispose of flowback and produced water generated in hydraulic fracturing or other fluids resulting from E&P activities. Applicable laws, including the Clean Water Act, impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States and require that permits or other approvals be obtained to discharge pollutants to such waters. For example, in 2015, the EPA and the Corps issued a final rule outlining their position on the federal jurisdictional reach over waters of the United States, but the rule has been challenged in federal district court on the grounds that it unlawfully expands the reach of Clean Water Act programs, and implementation of the rule has been enjoined in twenty-eight states, including North Dakota, Montana and Texas, where we conduct operations, pending resolution of the legal challenges. In July 2017, the EPA and the Corps published a proposed rule to rescind the 2015 rule and, in February 2018, the agencies published a final rule adding a February 6, 2020 applicable date to the 2015 rule. The February 2018 rule extending the 2015 final rule’s date of applicability is currently subject to litigation. Also, in December 2018, the EPA and the Corps published a proposed rule defining the Clean Water Act’s jurisdiction for which the agencies will seek public comment. As a result of these developments, future implementation of the rule is uncertain at this time. Additionally, regulations implemented under the Clean Water Act and similar state laws prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into coastal waters. The Clean Water Act and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and hazardous substances. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells and any inability to secure transportation and access to disposal wells with sufficient capacity to accept all of our or our customers' flowback and produced water on economic terms may increase our or our customers' operating costs and cause delays, interruptions or termination of our or our customers' operations, the extent of which cannot be predicted.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls, substantial changes to existing integrity management programs, or more stringent enforcement of applicable legal requirements could subject us to increased capital and operating costs and operational delays.

Certain of our pipelines are subject to regulation by PHMSA under the HLPSA with respect to oil and condensate and the NGPSA with respect to natural gas. The HLPSA and NGPSA govern the design, installation, testing, construction, operation, replacement and management of oil and natural gas pipeline facilities. These laws have resulted in the adoption of rules by PHMSA, that, among other things, require transportation pipeline operators to implement integrity management programs, including more frequent inspections, correction of identified anomalies and other measures to ensure pipeline safety in HCAs, such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. In addition, states have adopted regulations similar to existing PHMSA regulations for certain intrastate natural gas and hazardous liquid pipelines, which regulations may impose more stringent requirements than found under federal law. Historically, our pipeline safety compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance costs will not have a material adverse effect on our business and operating results. New pipeline safety laws or regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increases in governmental enforcement adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs and operational delays.

Legislation in recent years has resulted in more stringent mandates for pipeline safety and has charged PHMSA with developing and adopting regulations that impose increased pipeline safety requirements on pipeline operators. The HLPSA and NGPSA were amended by the 2011 Pipeline Safety Act, which among other things, increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. In 2016, the 2016 Pipeline Safety Act was passed, extending PHMSA's statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and developing new safety standards for natural gas storage facilities. The 2016 Act also empowers PHMSA to address unsafe conditions or practices constituting imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of hazardous liquid or natural gas pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in 2016 to implement the agency's expanded authority to address such conditions or practices that pose an imminent hazard to life, property or the environment.

The adoption of new or amended regulations by PHMSA that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on our results of operations. For example, in January 2017, PHMSA issued a final rule that significantly extends and expands the reach of certain PHMSA hazardous liquid pipeline integrity management requirements, such as, for example, periodic assessments, leak detection and repairs, regardless of the pipeline's proximity to a HCA. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, the date of implementation of this final rule by publication in the Federal Register remains uncertain following the January 2017 change in Presidential Administrations. In a second example, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for natural gas pipelines in newly defined "moderate consequence areas" that contain as few as five dwellings within a potential impact area; requiring natural gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their MAOP; and requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements for natural gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. PHMSA has split this proposed rule into three separate rulemaking proceedings and is expected to finalize those proceedings in 2019. New legislation or any new regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs and operational delays. In the absence of the PHMSA pursuing any legal requirements, state agencies, to the extent authorized, may pursue state standards, including standards for rural gathering lines.

We do not own all of the land on which our pipelines and associated facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines and associated facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Additionally, following a decision issued in May 2017 by the federal Tenth Circuit Court of Appeals, tribal ownership of even a very small fractional interest in an allotted

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land, that is, tribal land owned or at one time owned by an individual Indian landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where an existing pipeline rights-of-way may soon lapse or terminate serves as an additional impediment for pipeline operators. We cannot guarantee that we will always be able to renew existing rights-of-way or obtain new rights-of-way without experiencing significant costs. Any loss of rights with respect to our real property, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial position and ability to make cash distributions to the unitholders of OMP.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory drilling locations or to identify, evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drilling attempts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining qualified personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect our operations.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Thomas B. Nusz, our Chairman and Chief Executive Officer, and Taylor L. Reid, our President and Chief Operating Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Seasonal weather conditions adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Williston Basin and Delaware Basin are adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and natural gas activities cannot be conducted as effectively during the winter months. Severe winter weather conditions limit and may temporarily halt our ability to operate during such conditions. Results of operations in the Delaware Basin may also be negatively affected by inclement weather during the winter months. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs.

The inability of one or more of our customers or affiliates 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 ($234.2 million in receivables at December 31, 2018), which we market to energy marketing companies, refineries and affiliates, and joint interest receivables ($93.9 million at December 31, 2018).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. For the year ended December 31, 2018, no purchaser accounted for more than 10% of the Company’s total sales. For the year ended December 31, 2017, sales to Shell Trading (US) Company accounted for approximately 16% of our total sales. For the year ended December 31, 2016, sales to PBF

Holding Company LLC accounted for approximately 10% of our total sales. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2017 and 2016. We do not require all of our customers to post collateral. 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.

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Joint interest receivables arise from billing entities who own a partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we choose to drill. We have limited ability to control participation in our wells. For the year ended December 31, 2018, we recorded bad debt expense of $1.5 million as a result of our assessment that it is probable certain receivables may not be collected.

In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Derivative assets and liabilities arising from derivative contracts with the same counterparty are reported on a net basis, as all counterparty contracts provide for net settlement. At December 31, 2018, we had derivatives in place with nine counterparties and a total net derivative asset of $106.8 million.

We may be subject to risks in connection with acquisitions because of uncertainties in evaluating recoverable reserves, well performance and potential liabilities, as well as uncertainties in forecasting oil and gas prices and future development, production and marketing costs, and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategic tactics. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;
- validity of the seller's title to the properties, which may be less than expected at the time of signing the purchase agreement; and
- potential environmental and other liabilities, together with associated litigation of such matters.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities or title defects in excess of the amounts claimed by us before closing and acquire properties on an "as is" basis. Indemnification from the sellers will generally be effective only during a limited time period after the closing and subject to certain dollar limitations and minimums. We may not be able to collect on such indemnification because of disputes with the sellers or their inability to pay. Moreover, there is a risk that we could ultimately be liable for unknown obligations related to acquisitions, which could materially adversely affect our financial condition, results of operations or cash flows.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- an inability to secure, on acceptable terms, sufficient financing that may be required in connection with expanded operations and unknown liabilities; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating assets could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. In addition, even if we successfully integrate the assets acquired in an acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame.

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If we fail to realize the anticipated benefits of a significant acquisition, such as the Delaware Basin Acquisition, our results of operations may be lower than we expect.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated net proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, in oil and natural gas industry conditions, by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, failure to retain key personnel, an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from an acquisition, our results of operations and stock price may be adversely affected.

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

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest.

Prior to the drilling of an oil or gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in the title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may adversely impact our ability in the future to increase production and reserves. There is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

The enactment of derivatives legislation and regulation could have an adverse effect on our ability to use derivative instruments to reduce the negative effect of commodity price changes, interest rate and other risks associated with our business.

On July 21, 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act, the CFTC has proposed new regulations to set position limits for certain futures, options and swap contracts in designated physical commodities, including, among others, oil and natural gas. The Dodd-Frank Act and CFTC rules have also designated certain types of swaps (thus far, only certain interest rate swaps and credit default swaps) for mandatory clearing and exchange trading, and may designate other types of swaps for mandatory clearing and exchange trading in the future. To the extent that we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply with the clearing and exchange trading requirements or to take steps to qualify for an exemption to such requirements. In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the non-financial end-user exception from margin requirements for swaps to other market participants, such as swap dealers, these rules may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the non-financial end-user exception, we could be required to post initial or variation margin, which would impact liquidity and reduce our cash. This would in turn reduce our ability to execute hedges to reduce risk and protect cash flows. Other regulations to be promulgated under the Dodd-Frank Act also remain to be finalized. As a result, it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Further, to the extent our revenues are unhedged, they could be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial position, results of operations and cash flows. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations.

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Final regulations relating to and interpretations of provisions of the Tax Act may vary from our current interpretation of such legislation and could adversely affect our financial position, results of operations and cash flows.

The U.S. federal income tax legislation enacted on December 22, 2017, commonly referred to as the Tax Act, is highly complex and subject to interpretation. The presentation of our financial position and results of operations is based upon our current interpretation of the provisions contained in the Tax Act. In the future, the Treasury Department and the Internal Revenue Service are expected to issue final regulations and additional interpretive guidance with respect to the provisions of the Tax Act. Any significant variance of our current interpretation of such provisions from any future final regulations or interpretive guidance could adversely affect our financial position, results of operations and cash flows.

We may not be able to utilize a portion of our net operating losses ("NOLs") to offset future taxable income for U.S. federal or state tax purposes, which could adversely affect our net income and cash flows.

As of December 31, 2018, we had significant federal and state income tax NOLs, which will begin to expire in 2033 and 2020 for U.S. federal and state income tax purposes, respectively. Utilization of these NOLs depends on many factors, including our 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 an NOL that may be used to offset taxable income when a corporation has undergone an "ownership change." Determining the limitations under Section 382 is technical and highly complex. We continue to study whether we have undergone or may in the future undergo an ownership change under Section 382. If an ownership has occurred or occurs in the future, we may be prevented from fully utilizing our NOLs, which could adversely affect our financial position, results of operations and cash flows.

An unfavorable resolution of the Mirada Litigation could have a material adverse effect on our business, financial condition, results of operations and cash flows.

On March 23, 2017, Mirada (as defined in "Item 3. Legal Proceedings") filed a lawsuit against Oasis Petroleum Inc., OPNA and Oasis Midstream Services LLC in the 334th Judicial District Court of Harris County, Texas. Mirada asserts that it is a working interest owner in certain acreage owned and operated by us and that we have breached certain agreements our predecessors in interest previously entered into with Mirada, or its predecessors interest, with respect to such acreage. We filed an answer denying all of Mirada's claims, and intend and continue to vigorously defend against Mirada's claims. Discovery is ongoing, and each of the parties has made a number of procedural filings and motions, and additional filings and motions can be expected over the course of the claim. On June 30, 2017, Mirada amended its original petition to add a claim that we have breached certain agreements by charging Mirada for midstream services provided by its affiliates and to seek a declaratory judgment that Mirada is entitled to be paid its share of total proceeds from the sale of hydrocarbons received by OPNA or any affiliate of OPNA without deductions for midstream services provided by OPNA or its affiliates. On February 2, 2018 and February 16, 2018, Mirada filed a second and third amended petition, respectively. In these filings, Mirada alleged new legal theories for being entitled to enforce the underlying contracts and added Bighorn DevCo LLC, Bobcat DevCo LLC and Beartooth DevCo LLC as defendants, asserting that these entities were created in bad faith in an effort to avoid contractual obligations owed to Mirada. On March 2, 2018, Mirada filed a fourth amended petition that described Mirada's alleged ownership and assignment of interests in assets purportedly governed by agreements at issue in the lawsuit. On August 31, 2018, Mirada filed a fifth amended petition that added Oasis Midstream Partners LP as a defendant, asserting that it was created in bad faith in an effort to avoid contractual obligations owed to Mirada. Mirada may further amend its petition from time to time to assert additional claims as well as defendants. Trial was previously scheduled for May 2019, but, in connection with a request by the parties to continue the trial until a later date, the trial is now scheduled for February 20, 2020. For further information regarding this lawsuit, please read "Item 3. Legal Proceedings." We cannot predict the outcome of the Mirada Litigation or the amount of time and expense that will be required to resolve the lawsuit. If such litigation were to be determined adversely to our interests, or if we were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on our business, results of operations and financial condition. Such an adverse determination could materially impact our ability to operate our properties in Wild Basin or develop our identified drilling locations in Wild Basin on our current development schedule. A determination that Mirada has a right to participate in our midstream operations could materially reduce the interests of us in our current assets and future midstream opportunities and related revenues in Wild Basin. In addition, we have agreed to indemnify OMP for any losses resulting from this litigation under the omnibus agreement we entered into with OMP at the time of its initial public offering.

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Terrorist attacks or cyber-attacks could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks or cyber-attacks may significantly affect the energy industry, including our operations and those of our potential customers, as well as general economic conditions, consumer confidence and spending and market liquidity. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. Also, destructive forms of protests and opposition by extremists and other disruptions, including acts of sabotage or eco-terrorism, against oil and natural gas development and production or midstream processing or transportation activities could potentially result in damage or injury to persons, property or the environment or lead to extended interruptions of our operations. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain midstream activities. For example, software programs are used to manage gathering and transportation systems and for compliance reporting. The use of mobile communication devices has increased rapidly. Industrial control systems such as SCADA (supervisory control and data acquisition) now control large scale processes that can include multiple sites and long distances, such as oil and gas pipelines. We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data and to communicate with our employees and business partners. Our business partners, including vendors, service providers and financial institutions, are also dependent on digital technology. The technologies needed to conduct midstream activities make certain information the target of theft or misappropriation.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, also has increased. A cyber attack could include gaining unauthorized access to digital systems or data for purposes of misappropriating assets or sensitive information, corrupting data or causing operational disruption. SCADA-based systems are potentially vulnerable to targeted cyber attacks due to their critical role in operations.

Our technologies, systems, networks and data, and those of our business partners, may become the target of cyber attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information or other disruption of our business operations. In addition, certain cyber incidents, such as unauthorized surveillance or a cyber breach, may remain undetected for an extended period.

A cyber incident involving our information systems or data and related infrastructure, or that of our business partners, including any vendor or service provider, could disrupt our business plans and negatively impact our operations in the following ways, among others:

- supply chain disruptions, which could delay or halt development of additional infrastructure, effectively delaying the start of cash flows from the project;
- delays in delivering or failure to deliver product at the tailgate of our facilities, resulting in a loss of revenues;
- operational disruption resulting in loss of revenues;
- events of non-compliance that could lead to regulatory fines or penalties; and
- business interruptions that could result in expensive remediation efforts, distraction of management, damage to our reputation or a negative impact on the price of our units.

Our implementation of various controls and processes, including globally incorporating a risk-based cyber security framework, to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure is costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. As cyber threats 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 information security vulnerabilities.

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Ineffective internal controls could impact our business and financial results.

Our internal control over financial reporting may not prevent or detect misstatements because of its inherent limitations, including the possibility of human error, the circumvention or overriding of controls, or fraud. Even effective internal controls can provide only reasonable assurance with respect to the preparation and fair presentation of financial statements. If we fail to maintain the adequacy of our internal controls, including any failure to implement required new or improved controls, or if we experience difficulties in their implementation, our business and financial results could be harmed and we could fail to meet our financial reporting obligations. In connection with the preparation of our consolidated financial statements for the year ended December 31, 2018, we identified errors in our previously issued 2017 annual consolidated financial statements and in each of the interim periods within 2018 and 2017. These prior period errors related to the manner in which we accounted for certain crude oil purchase and sale arrangements. See Note 2 to our consolidated financial statements for more information on this revision, and for a discussion of our internal control over financial reporting and a description of the identified material weakness and the remediation efforts being implemented for that material weakness, see “Management's report on internal control over financial reporting” included in Item 9A of this report.

A material weakness in our internal control over financial reporting could adversely impact our ability to provide timely and accurate financial information. In response to the material weakness identified, management has developed a remediation plan, including enhanced communication and improved management review of crude oil purchase and sale arrangements in order to remediate this material weakness, and has begun working on that remediation plan. However, if our remedial measures are insufficient to address the material weakness or if additional material weaknesses or significant deficiencies in our internal control over financial reporting are discovered or occur in the future, we may not be able to timely or accurately report our financial condition, results of operations or cash flows or maintain effective disclosure controls and procedures.

Risks Relating to our Common Stock

We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, our shareholders’ only opportunity to achieve a return on their investment is if the price of our stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently restricted from making any cash dividends pursuant to the terms of our Revolving Credit Facilities and the indentures governing our Senior Notes. Consequently, our shareholders’ only opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the shareholder sells their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the shareholder paid.

Our amended and restated certificate of incorporation, as amended, and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation, as amended, authorizes our Board of Directors to issue preferred stock without stockholder approval. If our Board of Directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation, as amended, and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- a classified Board of Directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the Board of Directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any “interested stockholder,” meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our Board of Directors.

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Conversion of the Senior Convertible Notes may dilute the ownership interest of existing stockholders, or may otherwise depress the market price of our common stock.

The conversion of some or all of the Senior Convertible Notes (as defined in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources") may dilute the ownership interests of existing stockholders of our common stock. Any sales in the public market of the shares of our common stock issuable upon such conversion could adversely affect prevailing market prices of our common stock. In addition, the existence of the Senior Convertible Notes may encourage short selling by market participants because the conversion of the Senior Convertible Notes could be used to satisfy short positions, and anticipated conversion of the Senior Convertible Notes into shares of our common stock could depress the market price of our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information required by Item 2. is contained in Item 1. Business.

Item 3. Legal Proceedings

Mirada litigation

On March 23, 2017, Mirada Energy, LLC, Mirada Wild Basin Holding Company, LLC and Mirada Energy Fund I, LLC (collectively, “Mirada”) filed a lawsuit against Oasis, OPNA and Oasis Midstream Services LLC, seeking monetary damages in excess of $100 million, declaratory relief, attorneys’ fees and costs (Mirada Energy, LLC, et al. v. Oasis Petroleum North America LLC, et al.; in the 334th Judicial District Court of Harris County, Texas; Case Number 2017-19911). Mirada asserts that it is a working interest owner in certain acreage owned and operated by the Company in Wild Basin. Specifically, Mirada asserts that the Company has breached certain agreements by: (1) failing to allow Mirada to participate in the Company’s midstream operations in Wild Basin; (2) refusing to provide Mirada with information that Mirada contends is required under certain agreements and failing to provide information in a timely fashion; (3) failing to consult with Mirada and failing to obtain Mirada’s consent prior to drilling more than one well at a time in Wild Basin; and (4) overstating the estimated costs of proposed well operations in Wild Basin. Mirada seeks a declaratory judgment that the Company be removed as operator in Wild Basin at Mirada’s election and that Mirada be allowed to elect a new operator; certain agreements apply to the Company and Mirada and Wild Basin with respect to this dispute; the Company be required to provide all information within its possession regarding proposed or ongoing operations in Wild Basin; and the Company not be permitted to drill, or propose to drill, more than one well at a time in Wild Basin without obtaining Mirada’s consent. Mirada also seeks a declaratory judgment with respect to the Company’s current midstream operations in Wild Basin. Specifically, Mirada seeks a declaratory judgment that Mirada has a right to participate in the Company’s Wild Basin midstream operations, consisting of produced water disposal, crude oil gathering and gas gathering and processing; that, upon Mirada’s election to participate, Mirada is obligated to pay its proportionate costs of the Company’s midstream operations in Wild Basin; and that Mirada would then be entitled to receive a share of revenues from the midstream operations and would not be charged any amount for its use of these facilities for production from the “Contract Area.”

On June 30, 2017, Mirada amended its original petition to add a claim that the Company has breached certain agreements by charging Mirada for midstream services provided by its affiliates and to seek a declaratory judgment that Mirada is entitled to be paid its share of total proceeds from the sale of hydrocarbons received by OPNA or any affiliate of OPNA without deductions for midstream services provided by OPNA or its affiliates.

On February 2, 2018 and February 16, 2018, Mirada filed a second and third amended petition, respectively. In these filings, Mirada alleged new legal theories for being entitled to enforce the underlying contracts and added Bighorn DevCo LLC, Bobcat DevCo LLC and Beartooth DevCo LLC as defendants, asserting that these entities were created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On March 2, 2018, Mirada filed a fourth amended petition that described Mirada’s alleged ownership and assignment of interests in assets purportedly governed by agreements at issue in the lawsuit. On August 31, 2018, Mirada filed a fifth amended petition that added Oasis Midstream Partners LP as a defendant, asserting that it was created in bad faith in an effort to avoid contractual obligations owed to Mirada.

The Company believes that Mirada’s claims are without merit, that the Company has complied with its obligations under the applicable agreements and that some of Mirada’s claims are grounded in agreements that do not apply to the Company. The Company filed answers denying all of Mirada’s claims and intends and continues to vigorously defend against Mirada’s claims. OMP has not yet filed an answer because it has not yet been served with process. Discovery is ongoing, and each of the parties has made a number of procedural filings and motions, and additional filings and motions can be expected over the course of the claim. Trial was previously scheduled for May 2019, but, in connection with a request by the parties to continue the trial until a later date, the trial is now scheduled for February 20, 2020. The Company cannot predict or guarantee the ultimate outcome or resolution of such matter. If such matter were to be determined adversely to the Company’s interests, or if the Company were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on the Company’s business, financial condition, results of operations or cash flows. Such an adverse determination could materially impact the Company’s ability to operate its properties in Wild Basin or develop its identified drilling locations in Wild Basin on its current development schedule. A determination that Mirada has a right to participate in the Company’s midstream operations could materially reduce the interests of the Company in their current assets and future midstream opportunities and related revenues in Wild Basin. In addition, the Company has agreed to indemnify OMP for any losses resulting from this litigation under the omnibus agreement it entered into with OMP at the time of OMP's initial public offering.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Holders. As of February 22, 2019, the number of record holders of our common stock was 797. Based on inquiry, management believes that the number of beneficial owners of our common stock is approximately 37,716 as of February 20, 2019.

On February 28, 2019, the last sale price of our common stock, as reported on the NYSE, was $5.59 per share.

Unregistered Sales of Securities. There were no sales of unregistered securities during the year ended December 31, 2018.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the three months ended December 31, 2018:

Period	Total Number of Shares Exchanged[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
October 1 – October 31, 2018	2,129	$ 14.23	—	—
November 1 – November 30, 2018	593	10.34	—	—
December 1 – December 31, 2018	527	7.14	—	—
Total	3,249	$ 0.08	—	—

(1) Represent shares that employees surrendered back to us that equaled in value the amount needed to pay payroll tax withholding obligations upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to repurchase shares of our common stock.

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Stock Performance Graph. The following performance graph and related information is "furnished" with the SEC and shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

The performance graph shown below compares the cumulative total return to our common stockholders as compared to the cumulative total returns on the Standard and Poor's 500 Index ("S&P 500") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P 500 O&G E&P") for the period of December 2013 through December 2018. The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common stock, the S&P 500 and the S&P 500 O&G E&P on December 31, 2013 at the closing price on such date; and
2. Dividends were reinvested.

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Item 6. Selected Financial Data

Set forth below is our summary historical consolidated financial data for the years ended December 31, 2014 through 2018. This information may not be indicative of our future results of operations, financial position and cash flows and should be read in conjunction with the consolidated financial statements and notes thereto and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" presented elsewhere in this Annual Report on Form 10-K. We believe that the assumptions underlying the preparation of our historical consolidated financial statements are reasonable.

	Year ended December 31,				
	2018	2017	2016[1]	2015	2014
	(In thousands, except per share data)				
Statement of operations data:					
Revenues:					
Oil and gas revenues[2]	$1,590,024	$1,034,634	$625,233	$721,672	$1,304,004
Purchased oil and gas sales[2]	551,808	133,542	10,272	—	—
Midstream revenues	119,040	72,752	35,406	23,769	11,614
Well services revenues	61,075	52,791	33,754	44,294	74,610
Total revenues	2,321,947	1,293,719	704,665	789,735	1,390,228
Expenses:					
Lease operating expenses	193,912	177,134	135,444	144,481	169,600
Midstream operating expenses	31,912	17,589	9,003	6,198	4,647
Well services operating expenses[3]	41,200	37,228	20,675	24,782	45,605
Marketing, transportation and gathering expenses[4]	107,193	55,740	30,108	31,610	29,133
Purchased oil and gas expenses[2]	554,307	134,615	10,258	—	—
Production taxes	133,696	88,133	56,565	69,584	127,648
Depreciation, depletion and amortization	636,296	530,802	476,331	485,322	412,334
Exploration expenses	27,432	11,600	1,785	2,369	3,064
Rig termination[5]	—	—	—	3,895	—
Impairment	384,228	6,887	4,684	46,109	47,238
General and administrative expenses[3]	121,346	91,797	89,342	89,549	92,306
Total operating expenses	2,231,522	1,151,525	834,195	903,899	931,575
Gain (loss) on sale of properties	28,587	1,774	(1,303)	—	186,999
Operating income (loss)	119,012	143,968	(130,833)	(114,164)	645,652
Other income (expense)					
Net gain (loss) on derivative instruments	28,457	(71,657)	(105,317)	210,376	327,011
Interest expense, net of capitalized interest	(159,085)	(146,837)	(140,305)	(149,648)	(158,390)
Gain (loss) on extinguishment of debt	(13,848)	—	4,741	—	—
Other income (expense)	121	(1,332)	160	(2,935)	195
Total other income (expense)	(144,355)	(219,826)	(240,721)	57,793	168,816
Income (loss) before income taxes	(25,343)	(75,858)	(371,554)	(56,371)	814,468
Income tax benefit (expense)	5,843	203,304	128,538	16,123	(307,591)
Net income (loss) including non-controlling interests	(19,500)	127,446	(243,016)	(40,248)	506,877
Less: Net income attributable to non-controlling interests[6]	15,796	3,650	—	—	—
Net income (loss) attributable to Oasis	$(35,296)	$123,796	$(243,016)	$(40,248)	$506,877
Earnings (loss) per share:					
Basic	$(0.11)	$0.53	$(1.32)	$(0.31)	$5.09
Diluted	(0.11)	0.52	(1.32)	(0.31)	5.05

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(1) Our statement of operations data for the years ended December 31, 2018 and 2016 do not include the full twelve months effects of our acquisitions for 2018 and 2016, respectively. We acquired such interests on February 14, 2018 for our 2018 acquisition and December 1, 2016 for our 2016 acquisition. See Note 10 to our consolidated financial statements for more information on the 2018 acquisition.

(2) We have revised the Consolidated Statements of Operations to correct the presentation of certain purchase and sale arrangements that should have been presented on a gross basis, which were previously recognized on a net basis in oil and gas revenues, by increasing purchased oil and gas sales and purchased oil and gas expenses by $45.6 million and $45.3 million, respectively, and decreasing oil and gas revenues by $0.3 million for the year ended December 31, 2017. See Note 2 to our consolidated financial statements for more information on this revision.

(3) For the years ended December 31, 2016 and 2015, well services operating expenses have been adjusted to include $2.9 million and $3.7 million, respectively, for certain well services direct field labor compensation expenses which were previously recognized in general and administrative expenses on our Consolidated Statements of Operations.

(4) Prior to the first quarter of 2017, marketing, transportation and gathering expenses included purchased oil and gas expenses, which represent the crude oil purchased primarily for blending at our crude oil terminal. Prior periods have been adjusted retrospectively to reflect these expenses in purchased oil and gas expenses on our Consolidated Statements of Operations. For the year ended December 31, 2016, marketing, transportation and gathering expenses have been adjusted to exclude $10.3 million of purchased oil and gas expenses.

(5) During the year ended December 31, 2015, we elected to early terminate certain drilling rig contracts and recorded rig termination expenses of $3.9 million.

(6) As OMP completed its initial public offering on September 25, 2017, net income attributable to non-controlling interests represents the OMP interest owned by the public for the period from September 25, 2017 through December 31, 2017. As of November 19, 2018, net income attributable to non-controlling interests represents the OMP interest owned by the public following the OMP Dropdown. See Note 3 to our consolidated financial statements for more information on the OMP Dropdown.

	At December 31,				
	2018	2017	2016	2015	2014
	(In thousands)				
Balance sheet data:					
Cash and cash equivalents	$22,190	$ 16,720	$ 11,226	$ 9,730	$ 45,811
Net property, plant and equipment	7,027,109	6,173,486	5,919,567	5,218,242	5,186,786
Total assets[(1)(2)]	7,626,142	6,622,929	6,178,632	5,649,375	5,909,076
Long-term debt[(1)]	2,735,276	2,097,606	2,297,214	2,302,584	2,670,664
Total stockholders' equity	3,918,880	3,513,579	2,923,157	2,319,342	1,872,301

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(1) Prior to 2015, we presented deferred financing costs related to our Senior Notes in other assets on our Consolidated Balance Sheets. Upon the adoption of new accounting guidance in 2015, such costs are presented as a deduction from the carrying value of long-term debt. As of December 31, 2018, 2017, 2016 and 2015, deferred financing costs related to our Senior Notes totaling $20.9 million, $23.0 million, $28.3 million and $35.4 million, respectively, were included in long-term debt on our Consolidated Balance Sheets. Prior periods have been adjusted retrospectively to reflect the period-specific effects of applying the new guidance. Reclassified amounts total $29.3 million for the year ended December 31, 2014.

(2) We have revised the Consolidated Balance Sheets to correct the presentation of certain purchase and sale arrangements that should have been presented on a gross basis, which were previously recognized on a net basis in accounts receivable, by increasing both accounts receivable and accrued liabilities by $7.8 million as of December 31, 2017, which resulted in increases in both total assets and total liabilities. See Note 2 to our consolidated financial statements for more information on this revision.

	Year ended December 31,				
	2018	2017	2016	2015	2014

	(In thousands)				
Other financial data:					
Net cash provided by operating activities	$996,421	$507,876	$228,018	$359,815	$872,516
Net cash used in investing activities	(1,613,536)	(714,760)	(1,070,828)	(479,148)	(1,077,452)
Net cash provided by financing activities	622,585	212,378	844,306	83,252	158,846

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results, and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in oil and natural gas prices, weather and environmental conditions, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary note regarding forward-looking statements."

Overview

We are an independent E&P company focused on the acquisition and development of onshore, unconventional oil and natural gas resources in the United States. Since our inception, we have acquired properties that provide current production and significant upside potential through further development. Our drilling activity has primarily been directed toward projects that we believe can provide us with repeatable successes in the Bakken and Three Forks formations. On February 14, 2018, we acquired approximately 22,000 net acres in the Delaware Basin from Forge Energy, LLC, representing our initial entry into the Delaware Basin (the "Permian Basin Acquisition"). The Permian Basin Acquisition more than doubled our core net inventory and allows us to further capitalize on our operational strengths. Oasis Petroleum North America LLC ("OPNA") and Oasis Petroleum Permian LLC ("OP Permian") conduct our domestic oil and natural gas E&P activities and own our proved and unproved oil and natural gas properties located in the North Dakota and Montana regions of the Williston Basin and the Texas regions of the Delaware Basin, respectively. In 2019, we will continue our drilling and completion activities in the Williston and Delaware Basins.

We also operate a midstream services business through OMS Holdings LLC ("OMS") and a well services business through Oasis Well Services LLC ("OWS"), both of which are separate reportable business segments that are complementary to our primary development and production activities. The midstream services business is conducted by Oasis Midstream Partners LP ("OMP" or "Oasis Midstream"), which completed an initial public offering in September 2017. We own the general partner and a majority of the outstanding units of OMP. The revenues and expenses related to work performed by OMS and OWS for OPNA's working interests are eliminated in consolidation and, therefore, do not directly contribute to our consolidated results of operations.

Our use of capital for acquisitions and development allows us to direct our capital resources to what we believe to be the most attractive opportunities as market conditions evolve. We have historically acquired properties that we believe will meet or exceed our rate of return criteria. We built our Williston Basin assets through acquisitions and development activities, which were financed with a combination of capital from private investors, borrowings under a $1,600.0 million senior secured revolving credit facility among OPNA, as Borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "Oasis Credit Facility") and a $400.0 million senior secured revolving credit facility among OMP, as parent, OMP Operating LLC, a subsidiary of OMP, as borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "OMP Credit Facility," and, together with the Oasis Credit Facility, our "Revolving Credit Facilities"), cash flows provided by operating activities, proceeds from our senior unsecured notes, proceeds from our public equity offerings, the sale of certain non-strategic oil and gas properties and cash settlements of derivative contracts. For acquisitions of properties with additional development, exploitation and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. In some instances, we have acquired non-operated property interests at what we believe to be attractive rates of return either because they provided an entry into a new area of interest or complemented our existing operations. In addition, the acquisition of non-operated properties in new areas provides us with geophysical and geologic data that may lead to further acquisitions in the same area, whether on an operated or non-operated basis. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives.

Due to the geographic concentration of our oil and natural gas properties in the Williston Basin and Delaware Basin, we believe the primary sources of opportunities, challenges and risks related to our business for both the short and long-term are:

- commodity prices for oil and natural gas;
- transportation capacity;
- availability and cost of services; and
- availability of qualified personnel.

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Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments as well as competition from other sources of energy. Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, as well as market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations and may fluctuate widely in the future. As a result of current oil prices, we have decreased our planned 2019 capital expenditures as compared to 2018, excluding acquisitions, and we are continuing to concentrate our drilling activities in certain areas that are the most economic in the Williston Basin and the Delaware Basin. A substantial or extended decline in prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broad array of potential purchasers. We enter into crude oil and natural gas sales contracts with purchasers who have access to transportation capacity, utilize derivative financial instruments to manage our commodity price risk and enter into physical delivery contracts to manage our price differentials. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows. Additionally, we sell a significant amount of our crude oil production through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. Currently, 86% of our gross operated oil production and substantially all of our gross operated natural gas production are connected to gathering systems. Please see "Item 1. Business—Marketing, transportation and major customers."

Our quarterly average net realized oil prices and average price differentials are shown in the tables below.

	2018				
	Q1	Q2	Q3	Q4	Year ended December 31, 2018
Average Realized Oil Prices ($/Bbl)(1)	$61.75	$65.82	$68.33	$52.01	$ 61.84
Average Price Differential ($/Bbl)(2)	$1.12	$2.07	$1.16	$6.79	$ 2.88
Average Price Differential Percentage(2)	2 %	3 %	2 %	12 %	4 %

	2017				
	Q1	Q2	Q3	Q4	Year ended December 31, 2017
Average Realized Oil Prices ($/Bbl)(1)	$47.03	$44.58	$46.34	$54.95	$ 48.51
Average Price Differential ($/Bbl)(2)	$4.88	$3.71	$1.84	$0.51	$ 2.62
Average Price Differential Percentage(2)	9 %	8 %	4 %	1 %	5 %

	2016				
	Q1	Q2	Q3	Q4	Year ended December 31, 2016
Average Realized Oil Prices ($/Bbl)(1)	$28.74	$40.81	$40.54	$44.57	$ 38.64
Average Price Differential ($/Bbl)(2)	$4.85	$4.86	$4.40	$4.91	$ 4.76
Average Price Differential Percentage(2)	14 %	11 %	10 %	10 %	11 %

(1) Realized oil prices do not include the effect of derivative contract settlements.

(2) Price differential reflects the difference between realized oil prices and WTI crude oil index prices.

Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations. Crude oil produced and sold in the Williston Basin has historically sold at a discount to WTI due to transportation costs and takeaway capacity. In the past, there have been periods when this discount has substantially increased due to oil production in the area increasing to a point that it temporarily surpassed the available pipeline transportation, rail transportation and refining capacity in the area. Expansions of both rail and pipeline facilities have reduced the prior constraint on oil transportation out of the Williston Basin and improved our price differentials received at the lease. In 2015, our price differentials relative to WTI strengthened as new pipelines opened to eastern Canada and U.S. markets and transportation on rail gradually declined. In the second half of 2017 and throughout most of 2018, our crude oil price differentials improved to less than $2.00 per barrel discount to WTI primarily due to the additional takeaway capacity of the Dakota Access Pipeline of over 500,000 barrels per day. In the fourth quarter of 2018, above average refinery maintenance combined with production in the Williston Basin reaching record levels temporarily caused basis differentials to widen to more than $6.50 per barrel discount to WTI, but have since come back in line with the first three quarters of 2018. Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations. In the Delaware Basin, price differentials in 2018 averaged more than $4.00 per barrel below WTI due to pipeline constraints. Expansions of pipelines

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occurring in 2019 should greatly reduce these differentials and provide ample takeaway for our Delaware production beginning in mid-2019.

We believe our large concentrated acreage position provides us with a multi-year inventory of drilling projects and requires forward planning visibility for obtaining services and necessary permits to drill wells. As a result of current oil prices, we are planning to decrease our well completions from 114 gross (79.0 net) operated wells in the Williston Basin in 2018 to approximately 70 gross operated wells in 2019. In the Delaware Basin, we are planning a slight increase in well completions from 7 gross (6.3 net) operated wells in 2018 to approximately 9 to 11 gross operated wells in 2019. Additionally, we have the ability to control the pace of completions to allow for additional financial flexibility. In 2018, we wrote off $0.9 million of leases that we did not expect to develop before their 2019 contract expirations, as we continue to focus our 2019 drilling activities in our core acreage in the Williston Basin and the Delaware Basin.

Our 2018, 2017 and 2016 activities included development and exploration drilling in the Williston Basin. Our current activities are focused on evaluating and developing our asset bases in the Williston Basin and the Delaware Basin and optimizing our operations. Based on the reserve reports prepared by our independent reserve engineers, we had 320.5 MMBoe of estimated net proved reserves with a PV-10 of $4,674.3 million and a Standardized Measure of $4,050.3 million at December 31, 2018, 312.2 MMBoe of estimated net proved reserves with a PV-10 of $3,683.7 million and a Standardized Measure of $3,300.7 million at December 31, 2017 and 305.1 MMBoe of estimated net proved reserves with a PV-10 of $2,627.8 million and a Standardized Measure of $2,483.1 million at December 31, 2016. Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months for the years ended December 31, 2018, 2017 and 2016 were $65.66 per Bbl for oil and $3.16 per MMBtu for natural gas, $51.34 per Bbl for oil and $2.99 per MMBtu for natural gas and $42.60 per Bbl for oil and $2.47 per MMBtu for natural gas, respectively. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Future operating costs, production taxes and capital costs were based on current costs as of each year-end. Changes in commodity prices and future operating costs may significantly affect the economic viability of drilling projects as well as the economic valuation and economic recovery of oil and gas reserves. A substantial or extended decline in oil prices could result in a significant decrease in our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure in the future.

Forward commodity prices and estimates of future production also play a significant role in determining impairment. As a result of lower commodity prices and their impact on our estimated future cash flows, we have continued to review our proved oil and natural gas properties for impairment. In 2018 and 2016, we recorded impairment charges of $134.8 million and $1.1 million, respectively, to write down our proved properties held for sale to their estimated fair value, less costs to sell. No proved impairment charges were recorded during the year ended December 31, 2017. The excess of our expected undiscounted future cash flows over the carrying value of our proved oil and natural gas properties in the Williston Basin has decreased slightly to $2,672.8 million as of December 31, 2018 as compared to an excess of $2,697.2 million at December 31, 2017. The excess of our expected undiscounted future cash flows over the carrying value of our proved oil and gas reserves in the Delaware Basin was $491.0 million as of December 31, 2018. The underlying commodity prices embedded in our expected undiscounted cash flows were determined using NYMEX forward strip prices for five years, escalating 3% per year thereafter. Our expected undiscounted estimated cash flows also included a 3% inflation factor applied to the future operating and development costs after five years.

In connection with the preparation of the our consolidated financial statements for the year ended December 31, 2018, we identified errors in our previously issued 2017 consolidated financial statements related to the presentation of certain crude oil purchase and sale arrangements. Specifically, although we previously presented the transactions on a net basis in oil and gas revenues, we were required to present these purchase and sale arrangements on a gross basis in purchased oil and gas expenses and purchased oil and gas sales. We have revised the 2017 annual consolidated financial statements to reflect the correction of errors, which had no effect on our net income. Management's

Discussion and Analysis of Financial Condition and Results of Operations set forth below reflects the effects of the revision. Please see Note 2 of our consolidated financial statements in “Item 8—Financial Statements and Supplementary Data" for more information related to the revision.

Highlights

- We increased our production guidance twice in 2018, which was adjusted for divestitures. Our production volumes averaged 88,288 barrels of oil equivalent per day (“Boepd”) (76.2% oil) in the fourth quarter of 2018, in-line with midpoint guidance. Our production volumes averaged 82,525 Boepd (76.5% oil) for the year ended December 31, 2018;
- We lowered our lease operating expenses (“LOE”) per barrels of oil equivalent (“Boe”) by over 12% year over year to $6.44 per Boe for the year ended December 31, 2018;

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- We completed and placed on production 121 gross (85.3 net) operated wells, including 114 gross (79.0 net) operated wells in the Williston Basin and 7 gross (6.3 net) operated wells in the Delaware Basin, while investing $942.2 million of exploration and production capital expenditures, which excludes acquisitions, other capital and midstream capital, during 2018;
- We closed and integrated the Permian Basin Acquisition of approximately 22,000 net core acres in the over-pressured oil window of the Delaware Basin. Additionally, we purchased adjacent acreage at attractive pricing, bringing our total position to over 23,000 net acres in the Delaware Basin;
- OMP completed the construction and startup of a second natural gas plant in Wild Basin, making us the second largest natural gas processor in North Dakota;
- We successfully executed a divestiture “dropdown” of additional interests in midstream subsidiaries to OMP for $251.4 million, which increased our holdings of OMP common units and reduced debt;
- We high-graded our portfolio since announcing the Permian Basin Acquisition, including non-strategic divestitures of $340.0 million, which helped reduce financial leverage during the year ended December 31, 2018; and
- Net cash provided by operating activities was $996.4 million for the year ended December 31, 2018. Adjusted EBITDA, a non-GAAP financial measure, was $958.7 million for the year ended December 31, 2018. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income (loss) including non-controlling interests and net cash provided by operating activities, see “Non-GAAP Financial Measures” below.

Results of Operations

Revenues

Our oil and gas revenues are derived from the sale of oil and natural gas production. These revenues do not include the effects of derivative instruments and may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Our purchased oil and gas sales are derived from the sale of oil and gas purchased through our marketing activities primarily to optimize transportation costs or for blending. Revenues and expenses from the sales and purchases are generally recorded on a gross basis, as we act as a principal in these transactions by assuming control of the purchased oil or gas before it is transferred to the customer. In certain cases, we enter into sales and purchases with the same counterparty in contemplation of one another, and these transactions are recorded on a net basis.

Our midstream revenues are primarily derived from produced and flowback water pipeline transport, produced and flowback water disposal, natural gas gathering and processing, fresh water sales and crude oil gathering and transportation. Our well services revenues are derived from well services, product sales and equipment rentals. The majority of our midstream revenues and all of our well services revenues are from services for third-party working interest owners in OPNA’s operated wells. Intercompany revenues for work performed by OMS and OWS for OPNA’s working interests are eliminated in consolidation and are therefore not included in midstream and well services revenues.

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The following table summarizes our revenues and production data for the periods presented:

	Year ended December 31,		
	2018	2017	2016
Operating results (in thousands)			
Revenues			
Oil revenues[1]	$1,425,409	$912,806	$586,308
Natural gas revenues	164,615	121,828	38,925
Purchased oil and gas sales[1]	551,808	133,542	10,272
Midstream revenues	119,040	72,752	35,406
Well services revenues	61,075	52,791	33,754
Total revenues	$2,321,947	$1,293,719	$704,665
Production data			
Williston Basin			
Oil (MBbls)	21,786	18,818	15,174
Natural gas (MMcf)	40,550	31,946	19,573
Oil equivalents (MBoe)	28,544	24,143	18,436
Average daily production (Boe per day)	78,203	66,144	50,372
Delaware Basin			
Oil (MBbls)	1,264	—	—
Natural gas (MMcf)	1,880	—	—
Oil equivalents (MBoe)	1,578	—	—
Average daily production (Boe per day)	4,322	—	—
Average sales prices			
Oil, without derivative settlements (per Bbl)	$61.84	$48.51	$38.64
Oil, with derivative settlements (per Bbl)[2]	52.65	47.99	46.68
Natural gas, without derivative settlements (per Mcf)[3]	3.88	3.81	1.99
Natural gas, with derivative settlements (per Mcf)[2][3]	3.84	3.86	1.99

(1) We have revised the Consolidated Statements of Operations to correct the presentation of certain purchase and sale arrangements that should have been presented on a gross basis, which were previously recognized on a net basis in oil and gas revenues, by increasing purchased oil and gas sales and purchased oil and gas expenses by $45.6 million and $45.3 million, respectively, and decreasing oil and gas revenues by $0.3 million for the year ended December 31, 2017. See Note 2 to our consolidated financial statements for more information on this revision.

(2) Realized prices include gains or losses on cash settlements for our commodity derivatives, which do not qualify for or were not designated as hedging instruments for accounting purposes. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

(3) Natural gas prices include the value for natural gas and natural gas liquids.

Year ended December 31, 2018 as compared to year ended December 31, 2017

Oil and gas revenues. Our oil and gas revenues increased $555.4 million, or 54%, to $1,590.0 million during the year ended December 31, 2018 as compared to the year ended December 31, 2017. The higher oil and natural gas production amounts sold increased revenues by $302.4 million, coupled with a $253.0 million increase due to higher oil and natural gas sales prices year over year. Average oil sales prices, without derivative settlements, increased by $13.33 per barrel to an average of $61.84 per barrel, and average natural gas sales prices, without derivative settlements and which include the value for natural gas and natural gas liquids, increased by $0.07 per Mcf to an average of $3.88 per Mcf for the year ended December 31, 2018 as compared to the year ended December 31, 2017. Average daily production sold increased by 16,381 Boe per day to 82,525 Boe per day during the year ended December 31, 2018 as compared to the year ended December 31, 2017. The increase in average daily production sold was primarily a result of our well completions during the year coupled with the Permian Basin Acquisition, offset by our divestitures. During the year ended December 31, 2018, we completed 79.2 total net wells in the Williston Basin. Since the closing of the Permian Basin Acquisition on February 14, 2018, we completed 6.3 total net wells in the Delaware Basin during the year ended December 31, 2018. See Note 10 to our consolidated financial statements for a description of our acquisitions.

Purchased oil and gas sales. Purchased oil and gas sales, which consist primarily of the sale of crude oil purchased to optimize transportation costs or for blending at our crude oil terminal, increased $418.3 million to $551.8 million for the year ended December 31, 2018 as compared to the year ended December 31, 2017, primarily due to higher volumes purchased and sold driven by increased market opportunities in the Williston Basin and in the Delaware Basin.

Midstream revenues. Midstream revenues were $119.0 million for the year ended December 31, 2018, which was a $46.3 million increase year over year. This increase was driven by a $25.8 million increase related to higher natural gas volumes gathered, compressed and processed, coupled with a $17.9 million increase related to higher water service volumes driven by an increase in producing wells and a $2.7 million increase related to higher oil volumes gathered, stabilized and transported.

Well services revenues. Well services revenues increased by $8.3 million to $61.1 million for the year ended December 31, 2018 as compared to the year ended December 31, 2017, which was due to a $6.6 million increase in well completion revenue due to the increased activity as a result of increasing the pace of our well completions and adding a second fracturing fleet in late 2017, coupled with a $0.8 million increase in equipment rentals and a $0.7 million increase in product sales to third parties.

Year ended December 31, 2017 as compared to year ended December 31, 2016

Oil and gas revenues. Our oil and gas revenues increased $409.4 million, or 65% to $1,034.6 million during the year ended December 31, 2017 as compared to the year ended December 31, 2016. The higher oil and natural gas production amounts sold increased revenues by $224.0 million, coupled with a $185.7 million increase due to higher oil and natural gas sales prices during the year ended December 31, 2017 as compared to the year ended December 31, 2016. Average oil sales prices, without derivative settlements, increased by $9.87 per barrel to an average of $48.51 per barrel, and average natural gas sales prices, without derivative settlements and which include the value for natural gas and natural gas liquids, increased by $1.82 per Mcf to an average of $3.81 per Mcf for the year ended December 31, 2017 as compared to the year ended December 31, 2016. Average daily production sold increased by 15,772 Boe per day to 66,144 Boe per day during the year ended December 31, 2017 as compared to the year ended December 31, 2016. The increase in average daily production sold was primarily a result of our acquisition completed on December 1, 2016 of approximately 55,000 net acres in the Williston Basin (the “Williston Basin Acquisition”) and our 63.0 total net well completions in the Williston Basin during the year ended December 31, 2017.

Purchased oil and gas sales. Purchased oil and gas sales, which consist primarily of the sale of crude oil purchased for blending at our crude oil terminal, which began in late 2016, or to optimize transportation costs, increased $123.3 million to $133.5 million for the year ended December 31, 2017 as compared to the year ended December 31, 2016.

Midstream revenues. Midstream revenues were $72.8 million for the year ended December 31, 2017, which was a $37.4 million increase year over year. This increase was driven by a $24.9 million increase related to higher natural gas volumes gathered, compressed and processed, coupled with a $10.4 million increase related to higher oil volumes gathered, stabilized and transported as a result of the start up of our first natural gas processing plant and our oil gathering system in the second half of 2016, respectively.

Well services revenues. In 2017, we increased the pace of our well completions and added a second fracturing fleet as well as third party crews. As a result, our well services revenues increased by $19.0 million to $52.8 million for the year ended December 31, 2017 as compared to the year ended December 31, 2016, which was due to a $10.7 million increase in well completion revenue due to the increased activity as a result of adding the second fracturing fleet, coupled with a $7.7 million increase in product sales to third parties.

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Expenses and other income

The following table summarizes our operating expenses, gain on sale of properties, other income and expenses and net income attributable to non-controlling interests for the periods presented:

	Year ended December 31,		
	2018	2017	2016
	(In thousands, except per Boe of production)		
Operating expenses			
Lease operating expenses	$ 193,912	$ 177,134	$ 135,444
Midstream operating expenses	31,912	17,589	9,003
Well services operating expenses(1)	41,200	37,228	20,675
Marketing, transportation and gathering expenses(2)	107,193	55,740	30,108
Purchased oil and gas expenses(3)	554,307	134,615	10,258
Production taxes	133,696	88,133	56,565
Depreciation, depletion and amortization	636,296	530,802	476,331
Exploration expenses	27,432	11,600	1,785
Impairment	384,228	6,887	4,684
General and administrative expenses(1)	121,346	91,797	89,342
Total operating expenses	2,231,522	1,151,525	834,195
Gain (loss) on sale of properties	28,587	1,774	(1,303)
Operating income (loss)	119,012	143,968	(130,833)
Other income (expense)			
Net gain (loss) on derivative instruments	28,457	(71,657)	(105,317)
Interest expense, net of capitalized interest	(159,085)	(146,837)	(140,305)
Gain (loss) on extinguishment of debt	(13,848)	—	4,741
Other income (expense)	121	(1,332)	160
Total other expense	(144,355)	(219,826)	(240,721)
Loss before income taxes	(25,343)	(75,858)	(371,554)
Income tax benefit	5,843	203,304	128,538
Net income (loss) including non-controlling interests	(19,500)	127,446	(243,016)
Less: Net income attributable to non-controlling interests(4)	15,796	3,650	—
Net income (loss) attributable to Oasis	$ (35,296)	$ 123,796	$ (243,016)
Costs and expenses (per Boe of production)			
Lease operating expenses	$ 6.44	$ 7.34	$ 7.35
Marketing, transportation and gathering expenses(2)	3.56	2.31	1.63
Production taxes	4.44	3.65	3.07

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(1) For the year ended December 31, 2017, certain well services direct field labor compensation expenses are included in well services operating expenses on our Consolidated Statements of Operations, which were previously recognized in general and administrative expenses on our Consolidated Statements of Operations. For the year ended December 31, 2016, well services operating expenses has been adjusted to include $2.9 million, which was previously recognized in general and administrative expenses on our Consolidated Statements of Operations.

(2) Prior to the first quarter of 2017, marketing, transportation and gathering expenses included purchased oil and gas expenses related to blending at our crude oil terminal on our Consolidated Statements of Operations. Prior periods have been adjusted retrospectively to reflect these expenses in purchased oil and gas expenses on our Consolidated Statements of Operations. For the year ended December 31, 2016, marketing, transportation and gathering expenses has been adjusted to exclude $10.3 million of purchased oil and gas expenses.

(3) We have revised the Consolidated Statements of Operations to correct the presentation of certain purchase and sale arrangements that should have been presented on a gross basis, which were previously recognized on a net basis in oil and gas revenues, by increasing purchased oil and gas sales and purchased oil and gas expenses by $45.6

million and

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$45.3 million, respectively, and decreasing oil and gas revenues by $0.3 million for the year ended December 31, 2017. See Note 2 to our consolidated financial statements for more information on this revision.

(4) As OMP completed its initial public offering on September 25, 2017, net income attributable to non-controlling interests represents the OMP interest owned by the public for the period from September 25, 2017 through December 31, 2017. As of November 19, 2018, net income attributable to non-controlling interests represents the OMP interest owned by the public following the OMP Dropdown. See Note 3 to our consolidated financial statements for more information on the OMP Dropdown.

Year ended December 31, 2018 as compared to year ended December 31, 2017

Lease operating expenses. Lease operating expenses increased $16.8 million to $193.9 million for the year ended December 31, 2018 as compared to the year ended December 31, 2017. The increase was primarily due to an increase in produced and flowback water disposal volumes being transported and injected into produced and flowback water disposal wells. In addition, lease operating expenses increased due to higher costs associated with operating an increased number of producing wells as a result of the Permian Basin Acquisition and our well completions, coupled with an increase in workover costs during the year ended December 31, 2018. We completed and placed on production 79.2 total net wells in the Williston Basin during the year ended December 31, 2018 as compared to 63.0 total net wells completed and placed on production during the year ended December 31, 2017. Since the closing of the Permian Basin Acquisition, we completed and placed on production 6.3 total net wells in the Delaware Basin during the year ended December 31, 2018. Lease operating expenses per Boe decreased from $7.34 per Boe to $6.44 per Boe primarily due to higher production volumes driven by improved downtime period over period.

Midstream operating expenses. Midstream operating expenses represent third-party working interest owners’ share of operating expenses incurred by OMS. The $14.3 million increase for the year ended December 31, 2018 as compared to the year ended December 31, 2017 was primarily related to the $8.0 million increase in gas gathering, compression and processing expenses driven by increased production, coupled with a $4.1 million increase related to higher water service volumes driven by an increase in producing wells and a $2.1 million increase related to higher oil volumes gathered, stabilized and transported.

Well services operating expenses. Well services operating expenses represent third-party working interest owners’ share of completion service costs, cost of goods sold and operating expenses incurred by OWS. The $4.0 million increase for the year ended December 31, 2018 as compared to the year ended December 31, 2017 was primarily attributable to increased well completion activity, coupled with increased trucking and maintenance expenses due to the addition of a second fracturing fleet in late 2017.

Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses increased $51.5 million year over year, or a $1.25 increase per Boe, which was primarily attributable to higher oil gathering and transportation expenses related to increased throughput on the Dakota Access Pipeline, which began operations in the second quarter of 2017, and our oil gathering system, which has been ramping up throughput since it began operations in the second half of 2016. In addition, natural gas gathering and processing expenses increased due to additional well connections on OMS infrastructure and the start up of our natural gas processing plants in the second half of 2016 and in the fourth quarter of 2018. Excluding non-cash valuation adjustments, our marketing, transportation and gathering expenses on a per Boe basis increased to $3.41 for the year ended December 31, 2018 as compared to $2.34 for the year ended December 31, 2017 primarily due to the higher aforementioned costs.

Purchased oil and gas expenses. Purchased oil and gas expenses, which represent the crude oil purchased primarily to optimize transportation costs or for blending at our crude oil terminal, increased $419.7 million to $554.3 million for the year ended December 31, 2018 as compared to December 31, 2017 primarily due to higher volumes purchased and sold driven by increased market opportunities in both the Williston Basin and the Delaware Basin.

Production taxes. Our production taxes for the years ended December 31, 2018 and 2017 were 8.4% and 8.5%, respectively, as a percentage of oil and natural gas sales. The production tax rate decreased year over year primarily due to a lower oil production mix, coupled with the addition of Delaware Basin assets following the Permian Basin Acquisition in February 2018 which bear a lower average production tax rate of approximately 4.8% as compared to 8.6% for the Williston Basin assets. North Dakota’s natural gas production tax is $0.0705 per Mcf, while its crude oil tax structure is based on a 5% production tax and a 5% oil extraction tax, resulting in a combined tax rate of 10% of crude oil revenues.

Depreciation, depletion and amortization (“DD&A”). DD&A expense increased $105.5 million to $636.3 million for the year ended December 31, 2018 as compared to the year ended December 31, 2017. The increase in DD&A expense for the year ended December 31, 2018 was primarily due to production increases from our wells completed during the year ended December 31, 2018 coupled with the Permian Basin Acquisition, offset by a decrease in the average DD&A rate to $21.12 per Boe for the year ended December 31, 2018 as compared to $21.99 per Boe for the year ended December 31, 2017. The decrease in the DD&A rate was primarily due to lower costs and higher estimated ultimate recoveries on our more recently completed wells than our historical averages, coupled with the removal of the divested non-strategic oil and gas properties (see Note 11 - Divestitures).

Exploration expenses. Exploration expenses increased $15.8 million to $27.4 million for the year ended December 31, 2018 as compared to the year ended December 31, 2017. This increase was primarily due to write-off of costs of $19.4 million related to exploratory well locations that are no longer in our current development plan, offset by a $4.4 million decrease in geological and geophysical expenses.

Impairment. During the years ended December 31, 2018 and 2017, we recorded total impairment charges of $384.2 million and $6.9 million, respectively. During the year ended December 31, 2018, we recorded an impairment loss of $383.4 million to adjust the carrying value of our properties for the Foreman Butte Divestiture to their estimated fair value, determined based on the expected sales price less costs to sell (see Note 11 — Divestitures). There were no impairment charges of proved oil and gas or other properties recorded during the year ended December 31, 2017, and no other impairment charges of proved oil and gas or other properties recorded during the year ended December 31, 2018. As a result of periodic assessments of our unproved properties not held-by-production, we recorded an impairment loss on our unproved oil and natural gas properties of $0.9 million and $6.6 million for the years ended December 31, 2018 and 2017, respectively, related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. For the year ended December 31, 2017, we also recorded non-cash impairment charges of $0.3 million for unproved properties due to leases that expired during the period. There were no such impairment charges recorded during year ended December 31, 2018. In determining the amount of non-cash impairment charges for such periods, we considered the application of the factors described under "Critical accounting policies and estimates—Impairment of proved properties" and "Critical accounting policies and estimates—Impairment of unproved properties."

General and administrative ("G&A") expenses. Our G&A expenses increased $29.5 million for the year ended December 31, 2018 from $91.8 million for the year ended December 31, 2017. E&P G&A increased $24.9 million year over year primarily due to increased employee compensation expenses as a result of organizational growth, coupled with increased costs related to the Permian Basin Acquisition. OMS G&A increased $4.7 million year over year primarily due to increased shared services allocations to our OMS segment, coupled with increased employee compensation expenses as a result of organizational growth within this segment. OWS G&A was $6.8 million and $6.9 million for the years ended December 31, 2018 and 2017, respectively. Consolidated G&A expenses included non-cash amortization for equity-based compensation of $29.3 million and $26.5 million in 2018 and 2017, respectively. Our full-time employee headcount increased 24% year over year.

Gain (loss) on sale of properties. For the year ended December 31, 2018, we recognized a $28.6 million net gain primarily related to three separate divestitures to sell certain non-strategic oil and gas properties in the Williston Basin (see Note 11 — Divestitures). For the year ended December 31, 2017, we recognized a $1.8 million net gain related to the sale of certain non-operated wells.

Derivatives. As a result of entering into derivative contracts and the effect of the forward strip oil and gas price changes, we incurred a $28.5 million net gain on derivative instruments, including net cash settlement payments of $213.5 million, for the year ended December 31, 2018, and a $71.7 million net loss on derivative instruments, including net cash settlement payments of $8.3 million, for the year ended December 31, 2017. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

Interest expense. Interest expense increased $12.3 million to $159.1 million for the year ended December 31, 2018 as compared to the year ended December 31, 2017 primarily due to interest expense related to the borrowings under our Revolving Credit Facilities and an increase in debt discount amortization related to our senior unsecured convertible notes. These increases in interest expense were partially offset by an increase in capitalized interest of $4.4 million due to higher costs for work in progress assets and a decrease in interest expense related to the repurchase of an aggregate principal amount of $390.6 million of outstanding senior unsecured notes and the issuance of $400.0 million senior unsecured notes due in 2026 at a lower interest rate of 6.25% in 2018. For the year ended December 31, 2018, the weighted average debt outstanding under the Oasis Credit Facility and the OMP Credit Facility were $554.7 million and $166.2 million, respectively, and the weighted average interest rates incurred on the outstanding borrowings were 3.9% and 3.8%, respectively. For the year ended December 31, 2017, the weighted average debt outstanding under the Oasis Credit Facility and the OMP Credit Facility were $416.2 million and $9.1 million, respectively, and the weighted average interest rates incurred on the outstanding borrowings were 2.8% and 3.1%, respectively. We capitalized $17.2 million and $12.8 million of interest costs for the years ended December 31, 2018 and 2017, respectively, which will be amortized over the life of the related assets.

Loss on extinguishment of debt. During the year ended December 31, 2018, we repurchased an aggregate principal amount of $413.5 million of our outstanding senior unsecured notes for an aggregate cost of $423.1 million, including fees. For the year ended December 31, 2018, we recognized a pre-tax loss related to the repurchase of $13.8 million, which included unamortized deferred financing costs write-offs of $4.0 million. During the year ended December 31, 2017, we did not repurchase any portion of our outstanding senior unsecured notes.

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Income tax benefit. Our income tax benefit for the years ended December 31, 2018 and 2017 was recorded at 23.1% and 268.0%, respectively, of pre-tax loss. The 244.9% decrease in the effective tax rate recorded is primarily due to (i) the change in tax rate under the Tax Act in 2017, (ii) the impact of non-deductible executive compensation, (iii) the impact of equity-based compensation shortfalls in 2018 as compared to equity-based compensation windfalls in 2017 and (iv) an increase in the valuation allowance recorded against our Montana net operating loss carryforwards in 2018. These decreases were partially offset by (i) the impact of OMP's earnings attributable to the non-controlling public limited partners which are not taxable to us and (ii) the impact of a change in the state rate at which deferred taxes are recorded.

Year ended December 31, 2017 as compared to year ended December 31, 2016

Lease operating expenses. Lease operating expenses increased $41.7 million to $177.1 million for the year ended December 31, 2017 as compared to the year ended December 31, 2016. The increase was primarily due to higher costs associated with operating an increased number of producing wells as a result of our well completions and the Williston Basin Acquisition, coupled with an increase in workover costs during the year ended December 31, 2017. We completed and placed on production 63.0 total net wells in the Williston Basin during the year ended December 31, 2017 as compared to 38.1 total net wells completed and placed on production during the year ended December 31, 2016. Lease operating expenses per Boe remained relatively flat year over year.

Midstream operating expenses. Midstream operating expenses represent third-party working interest owners' share of operating expenses incurred by OMS. The $8.6 million increase for the year ended December 31, 2017 as compared to the year ended December 31, 2016 was primarily related to the start up of our first natural gas processing plant and our oil gathering system during 2016.

Well services operating expenses. Well services operating expenses represent third-party working interest owners' share of completion service costs, cost of goods sold and operating expenses incurred by OWS. The $16.6 million increase for the year ended December 31, 2017 as compared to the year ended December 31, 2016 was primarily attributable to increased well completion product sales, coupled with increased trucking costs, maintenance and direct labor expenses due to the addition of a second fracturing fleet and higher well completion activity during 2017.

Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses increased $25.6 million year over year, or a $0.68 increase per Boe, which was primarily attributable to higher oil gathering and transportation expenses related to the start up of the Dakota Access Pipeline in 2017 and the start up of our oil gathering system in the second half of 2016. In addition, natural gas gathering and processing expenses increased due to additional well connections on OMS infrastructure and the start up of our first natural gas processing plant in the second half of 2016. Excluding non-cash valuation adjustments, our marketing, transportation and gathering expenses on a per Boe basis increased to $2.34 for the year ended December 31, 2017 as compared to $1.60 for the year ended December 31, 2016 primarily due to the higher aforementioned costs.

Purchased oil and gas expenses. Purchased oil and gas expenses, which represent the crude oil purchased primarily for blending at our crude oil terminal, which began in late 2016, or to optimize transportation costs, increased $124.4 million to $134.6 million for the year ended December 31, 2017 as compared to the year ended December 31, 2016.

Production taxes. Our production taxes for the years ended December 31, 2017 and 2016 were 8.5% and 9.1%, respectively, as a percentage of oil and natural gas sales. The production tax rate decreased year over year primarily due to a lower oil production mix. North Dakota's natural gas production tax is $0.0555 per Mcf, while its crude oil tax structure is based on a 5% production tax and a 5% oil extraction tax, resulting in a combined tax rate of 10% of crude oil revenues.

Depreciation, depletion and amortization. DD&A expense increased $54.5 million to $530.8 million for the year ended December 31, 2017 as compared to the year ended December 31, 2016. The increase in DD&A expense for the year ended December 31, 2017 was primarily due to production increases from our wells completed during the year ended December 31, 2017 coupled with the Williston Basin Acquisition, offset by a decrease in the average DD&A rate to $21.99 per Boe for the year ended December 31, 2017 as compared to $25.84 per Boe for the year ended December 31, 2016. The decrease in the DD&A rate was primarily due to lower well costs for wells completed during the second half of 2016 and the first half of 2017.

Exploration expenses. Exploration expenses increased $9.8 million to $11.6 million for the year ended December 31, 2017 as compared to the year ended December 31, 2016. This increase was primarily due to a $7.5 million increase in geological and geophysical expenses coupled with a $2.1 million write-off of costs primarily related to exploratory well locations that are no longer in our current development plan.

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Impairment. During the years ended December 31, 2017 and 2016, we recorded total impairment charges of $6.9 million and $4.7 million, respectively. For the year ended December 31, 2016, we recorded impairment charges of $3.6 million to adjust the carrying value of our properties held for sale to their estimated fair value, determined based on the expected sales price less costs to sell. No other impairment charges of proved oil and gas or other properties were recorded in 2017 or 2016. We also recorded non-cash impairment charges of $0.3 million and $0.2 million during the years ended December 31, 2017 and 2016, respectively, for unproved properties due to leases that expired during the period. As a result of periodic assessments of our unproved properties not held-by-production, we recorded an impairment loss on our unproved oil and natural gas properties of $6.6 million and $0.9 million for the years ended December 31, 2017 and 2016, respectively, related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. In determining the amount of non-cash impairment charges for such periods, we considered the application of the factors described under "Critical accounting policies and estimates—Impairment of proved properties" and "Critical accounting policies and estimates—Impairment of unproved properties."

General and administrative expenses. Our G&A expenses increased $2.5 million for the year ended December 31, 2017 from $89.3 million for the year ended December 31, 2016. OMS G&A increased $4.2 million year over year primarily due to increased employee compensation as a result of organizational growth within this segment due to the start up of our first natural gas processing plant in the third quarter of 2016, coupled with expenses incurred related to the initial public offering of OMP. E&P G&A was $77.6 million and $79.0 million and OWS G&A was $6.9 million and $7.2 million for the years ended December 31, 2017 and 2016, respectively. Consolidated G&A expenses included non-cash amortization for equity-based compensation of $26.5 million and $24.1 million in 2017 and 2016, respectively. Our full-time employee headcount increased 23% year over year.

Gain (loss) on sale of properties. For the year ended December 31, 2017, we recognized a $1.8 million gain related to the sale of certain non-operated wells. For the year ended December 31, 2016, we recognized a $1.3 million loss related to the sale of certain legacy wells that have been producing from conventional reservoirs such as the Madison, Red River and other formations in the Williston Basin other than the Bakken or Three Forks formations.

Derivatives. As a result of entering into derivative contracts and the effect of the forward strip oil and gas price changes, we incurred a $71.7 million net loss on derivative instruments, including net cash settlement payments of $8.3 million, for the year ended December 31, 2017, and a $105.3 million net loss on derivative instruments, including net cash settlement receipts of $122.0 million, for the year ended December 31, 2016. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

Interest expense. Interest expense increased $6.5 million to $146.8 million for the year ended December 31, 2017 as compared to the year ended December 31, 2016 primarily due to interest expense related to our senior unsecured convertible notes issued in September 2016, which includes debt discount amortization, and the borrowings under our Revolving Credit Facilities, coupled with a decrease in capitalized interest due to lower costs for work in progress assets as a result of the completion of our first natural gas processing plant in the third quarter of 2016. These increases were offset by the repurchase of an aggregate principal amount of $447.0 million of outstanding senior unsecured notes in 2016, which resulted in a $16.2 million decrease in interest costs. For the year ended December 31, 2017, the weighted average debts outstanding under the Oasis Credit Facility and the OMP Credit Facility were $416.2 million and $9.1 million, respectively, and the weighted average interest rates incurred on the outstanding borrowings were 2.8% and 3.1%, respectively. For the year ended December 31, 2016, the weighted average debt outstanding under the Oasis Credit Facility was $116.1 million, and the weighted average interest rate incurred on the outstanding borrowings thereunder was 2.2%. We capitalized $12.8 million and $16.8 million of interest costs for the years ended December 31, 2017 and 2016, respectively, which will be amortized over the life of the related assets.

Gain on extinguishment of debt. During the year ended December 31, 2016, we repurchased an aggregate principal amount of $447.0 million of our outstanding senior unsecured notes for an aggregate cost of $435.9 million, including accrued interest and fees. For the year ended December 31, 2016, we recognized a pre-tax gain related to the repurchase of $4.7 million, which included unamortized deferred financing costs write-offs of $6.4 million. During the year ended December 31, 2017, we did not repurchase any portion of our outstanding senior unsecured notes.

Income tax benefit. Our income tax benefit for the years ended December 31, 2017 and 2016 was recorded at 268.0% and 34.6%, respectively, of pre-tax loss. The 233.4% increase in the effective tax rate recorded is primarily due to (i) the change in tax rate under the Tax Act in 2017, (ii) the impact of non-deductible executive compensation, (iii) the impact of equity-based compensation windfalls in 2017 as compared to equity-based compensation shortfalls in 2016 and (iv) the impact of OMP's earnings attributable to the non-controlling public limited partners which are not taxable to us.

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Liquidity and Capital Resources

Our primary sources of liquidity as of the date of this report have been cash flows from operations, borrowings under our Revolving Credit Facilities, proceeds from our Senior Notes (as defined below), proceeds from the sale of certain non-strategic oil and gas properties and proceeds from public equity offerings. Our primary uses of cash have been for the acquisition and development of oil and natural gas properties and midstream infrastructure, interest payments on outstanding debt and repurchases of our Senior Notes (as defined below). We continually monitor potential capital sources, including equity and debt financings and potential asset monetization opportunities, in order to enhance liquidity and decrease leverage. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

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

	Year ended December 31,		
	2018	2017	2016
	(In thousands)		
Net cash provided by operating activities	$996,421	$507,876	$228,018
Net cash used in investing activities	(1,613,536)	(714,760)	(1,070,828)
Net cash provided by financing activities	622,585	212,378	844,306
Net change in cash and cash equivalents	$5,470	$5,494	$1,496

Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. Prices for oil declined significantly since mid-2014, which substantially decreased our cash flows provided by operating activities for the year ended December 31, 2016. During 2017 and the majority of 2018, prices for oil began to show upward movements resulting in increased cash flows provided by operating activities. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to mitigate the change in oil and natural gas prices on a portion of our production, thereby mitigating our exposure to oil and natural gas price declines, but these transactions may also limit our cash flow in periods of rising oil and natural gas prices. As of December 31, 2018, our derivative contracts in place cover 15.4 MMBbls of crude oil and 11.0 Bcf of natural gas in 2019.

On February 14, 2018, we borrowed $502.0 million under the Oasis Credit Facility to fund cash due at closing of the Permian Basin Acquisition and we also issued 46,000,000 shares of our common stock to Forge Energy to fund a portion of the Permian Basin Acquisition (see Note 10 – Acquisitions).

Our existing Revolving Credit Facilities provide additional liquidity. The Oasis Credit Facility has a current borrowing base of $1,600.0 million and an elected commitment amount of $1,350.0 million. The next redetermination of the borrowing base for the Oasis Credit Facility is scheduled for April 1, 2019. The OMP Credit Facility has a current borrowing capacity of $400.0 million.

We believe we have adequate liquidity to fund planned 2019 capital expenditures and to meet our near-term future obligations. For additional information on the impact of changing prices on our financial position, see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk.”

Cash flows provided by operating activities

Net cash provided by operating activities was $996.4 million, $507.9 million and $228.0 million for the years ended December 31, 2018, 2017 and 2016, respectively. The increase in cash flows provided by operating activities for the year ended December 31, 2018 as compared to 2017 was primarily the result of a 22% increase in oil production, a 27% increase in realized oil prices, a 33% increase in natural gas production and a 2% increase in realized natural gas prices. The increase in cash flows provided by operating activities for the year ended December 31, 2017 as compared to 2016 was primarily the result of a 26% increase in realized prices for oil, a 24% increase in oil production, a 92% increase in realized prices for natural gas and a 63% increase in natural gas production, coupled with increases in natural gas gathering and processing, produced and flowback pipeline transport and produced and flowback water disposal and increases in well services activity.

Working capital. Our working capital fluctuates primarily as a result of changes in commodity pricing and production volumes, capital spending to fund our exploratory and development initiatives and acquisitions and the impact of our outstanding derivative instruments. We had a working capital deficit of $57.6 million at December 31, 2018, however, we believe we have adequate liquidity to meet our working capital requirements. As of December 31, 2018, we had $972.2 million of liquidity available, including $22.2 million in cash and cash equivalents and $950.0 million of aggregate unused borrowing base committed capacity available under our Revolving Credit Facilities. As of December 31, 2017, we had a working capital deficit of $215.6 million.

Cash flows used in investing activities

We had net cash flows used in investing activities of $1,613.5 million, $714.8 million and $1,070.8 million during the years ended December 31, 2018, 2017 and 2016, respectively, primarily as a result of our capital expenditures for acquisition, drilling and development costs. The increase in cash used in investing activities for the year ended December 31, 2018 as compared to the year ended December 31, 2017 was primarily attributable to an increase in cash used for acquisitions year over year, primarily due to the Permian Basin Acquisition, and a 77% increase in cash capital expenditures primarily for drilling and development costs. Net cash used in investing activities during the year ended December 31, 2018 was primarily attributable to $1,149.0 million in other capital expenditures for the development of our properties, including E&P capital, the second natural gas processing plant and other midstream infrastructure, coupled with $581.7 million in acquisitions, primarily for the Permian Basin Acquisition and an acquisition to acquire certain exploration and production assets adjacent to the our existing Delaware position ("Other Delaware Acquisition") and $213.5 million for derivative settlements paid as a result of higher crude oil prices, partially offset by $333.2 million for proceeds from sale of properties. Net cash used in investing activities during the year ended December 31, 2017 was primarily attributable to $647.3 million in other capital expenditures for the development of our properties, including E&P capital, the second natural gas processing plant, and other midstream infrastructure coupled with $61.9 million for acquisitions, including the deposit of $47.3 million paid as part of the Permian Basin Acquisition, and $8.3 million for derivative settlements paid as a result of higher crude oil prices, partially offset by $5.8 million for proceeds from sale of properties. Net cash used in investing activities during the year ended December 31, 2016 was primarily attributable to $781.5 million for acquisitions, $426.3 million in other capital expenditures for the development of our properties, including E&P capital, the first natural gas processing plant and other midstream infrastructure, partially offset by $122.0 million for derivative settlements received as a result of lower crude oil prices.

Expenditures for the acquisition and development of oil and natural gas properties are the primary use of our capital resources. Our capital expenditures for the years ended December 31, 2018, 2017 and 2016 are summarized in the following table:

	Year ended December 31,		
	2018	2017	2016
	(In thousands)		
Capital expenditures			
E&P	$942,179	$517,329	$208,437
Well services	7,831	12,537	680
Other capital expenditures(1)	23,947	17,215	20,502
Total capital expenditures before acquisitions and midstream	$973,957	$547,081	$229,619
Midstream(2)	277,626	235,090	170,386
Total capital expenditures before acquisitions	1,251,583	782,171	400,005
Acquisitions	951,870	54,033	781,522
Total capital expenditures(3)	$2,203,453	$836,204	$1,181,527

(1) Other capital expenditures include such items as administrative capital and capitalized interest.

(2) Midstream capital expenditures attributable to OMP was $116.6 million for the year ended December 31, 2018.

(3) Total capital expenditures (including acquisitions) reflected in the table above differs from the amounts for capital expenditures and acquisitions shown in the statements of cash flows in our consolidated financial statements because amounts reflected in the table include changes in accrued liabilities from the previous reporting period for capital expenditures, while the amounts presented in the statements of cash flows are presented on a cash basis. In addition, for the year ended December 31, 2018, total capital expenditures (including acquisitions) reflected in the table includes consideration paid through the issuance of common stock in connection with the Permian Basin Acquisition. See Note 10 to our consolidated financial statements for more information on the Permian Basin Acquisition.

In 2018, we spent $2,203.5 million on capital expenditures, which represented a 164% increase as compared to the $836.2 million spent during 2017. This increase was primarily due to $951.9 million for acquisitions in 2018, including the Permian Basin Acquisition and the Other Delaware Acquisition. See Note 10 to our consolidated financial statements for more information on acquisitions. Excluding acquisitions, capital expenditures increased 60% as compared to 2017. The increase was attributable to increased drilling and completion activity as a result of higher commodity prices in 2018, coupled with higher capital expenditures for midstream, primarily related to the second natural gas processing plant constructed in our Wild Basin area in North Dakota and the development of additional midstream infrastructure in the Wild Basin area in North Dakota.

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During 2018, we participated in 137 gross wells (85.5 net) that were completed and placed on production, and, as operator, we completed and placed on production 121 gross (85.3 net) of these wells. In addition, as of December 31, 2018, we had 64 gross operated wells awaiting completion in the Bakken and Three Forks formations in the Williston Basin and 4 gross operated wells awaiting completion in the Wolfcamp and Bone Spring formations in the Delaware Basin. Our land leasing and acquisition activity is focused in and around our existing core consolidated land positions in the Williston Basin as well as our acquired acreage in the Delaware Basin.

As a result of current oil prices, we have decreased our planned 2019 capital expenditures as compared to 2018 capital expenditures, excluding acquisitions. We anticipate investing between $690 million and $730 million in 2019 as follows:

	Plan for the year ended December 31, 2019
	(In thousands)
E&P and other capital[1]	$540,000 - $560,000
Midstream capital[2]	150,000 - 170,000
Total capital expenditures	$690,000 - $730,000

(1) E&P and other capital expenditures include OWS and administrative capital and excludes capitalized interest of approximately $15 million.

(2) Midstream capital expenditures include approximately $19 million to $21 million for midstream capital expenditures attributable to Oasis.

While we have planned approximately $690 million to $730 million for total capital expenditures in 2019, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling and operations results as the year progresses. Furthermore, if we acquire additional acreage, our capital expenditures may be higher than planned. We believe that cash on hand, including cash flows from operating activities, proceeds from cash settlements under our derivative contracts and availability under our Revolving Credit Facilities should be sufficient to fund our 2019 capital expenditure plan and to meet our future obligations. However, because the operated wells funded by our 2019 drilling plan represent only a small percentage of our potential drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of potential drilling locations should we elect to do so.

Our capital plan may further be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil prices decline substantially or for an extended period of time, we could defer a significant portion of our planned capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control. We actively review acquisition opportunities on an ongoing basis. Our ability to make significant acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us or at all.

Cash flows provided by financing activities

Net cash provided by financing activities was $622.6 million, $212.4 million and $844.3 million for the years ended December 31, 2018, 2017 and 2016, respectively. For the year ended December 31, 2018, cash sourced through financing activities was provided by the borrowings under our Revolving Credit Facilities, proceeds from the issuance of senior unsecured notes and net proceeds from the sale of OMP common units (see Note 3 – Oasis Midstream Partners LP), net of offering costs, offset by principal payments on our Revolving Credit Facilities and the repurchase of a portion of our Senior Notes. For the year ended December 31, 2017, cash sourced through financing activities was provided by net proceeds from the issuance of our common stock (see Note 16 – Common Stock), net of offering costs, and net proceeds from the sale of OMP common units (see Note 3 – Oasis Midstream Partners LP), net of offering costs, partially offset by principal payments on our Revolving Credit Facilities. For the year ended December 31, 2016, cash sourced through financing activities was provided by net proceeds from the issuance of our common stock, the issuance of our Senior Convertible Notes and the borrowings under the Oasis Credit Facility, partially offset by the repurchase of a portion of our Senior Notes.

Senior secured revolving line of credit. We have the Oasis Credit Facility, which has an overall senior secured line of credit of $3,000.0 million as of December 31, 2018. The Oasis Credit Facility is restricted to a borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. The maturity date of the Oasis Credit Facility is the earlier of (i) October 16, 2023, (ii) 90 days prior to the maturity date of our 2022 and 2023 Senior Notes, of which $1,267.6 million is outstanding, to the extent such 2022 and 2023 Senior Notes are not retired or refinanced to have a maturity date at least 90 days after October 16, 2023 and (iii) 90 days prior to the maturity date of our 2023 Senior Convertible

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Notes (as defined below), of which $300.0 million is outstanding, to the extent such 2023 Senior Convertible Notes are not retired, converted, redeemed or refinanced to have a maturity date at least 90 days after October 16, 2023.

On February 26, 2018, we entered into an amendment to the Oasis Credit Facility, resulting in the aggregate elected commitment being increased from $1,150.0 million to $1,350.0 million and two new lenders being added to the bank group. On April 19, 2018, the lenders under the Oasis Credit Facility (the “Lenders”) completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2018, resulting in us entering into the Twelfth Amendment to the Second Amended and Restated Credit Agreement to the Oasis Credit Facility, which (i) reaffirmed the borrowing base and the aggregate elected commitment at $1,600.0 million and $1,350.0 million, respectively, (ii) removed the legacy anti-cash hoarding provisions, (iii) reduced the coverage threshold with respect to mortgaged properties and (iv) amended the asset sale covenant to give additional flexibility to trade oil and gas properties. In addition, in connection with such amendment, OP Permian became a guarantor under the Oasis Credit Facility.

On October 16, 2018, we entered into a third amended and restated credit agreement (the “Third Amended Credit Facility”) for the Oasis Credit Facility. In connection with entry into the Third Amended Credit Facility, the semi-annual redetermination of the borrowing base was completed on October 16, 2018, which reaffirmed the borrowing base and the aggregate elected commitment at $1,600.0 million and $1,350.0 million, respectively, and the overall credit facility increased from $2,500.0 million to $3,000.0 million. Pursuant to the Third Amended Credit Facility, the credit facility was extended from April 2020 to October 2023, provided that our 2022 and 2023 Notes (as defined below) are retired or refinanced 90 days prior to their respective maturities. All other significant rates, terms and conditions of the Third Amended Credit Facility remained the same. The next redetermination of the Oasis Credit Facility’s borrowing base is scheduled for April 1, 2019.

As of December 31, 2018, the Oasis Credit Facility contains covenants that include, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against making dividends, distributions and redemptions, subject to permitted exceptions;
- a prohibition against making investments, loans and advances, subject to permitted exceptions;
- restrictions on creating liens and leases on our assets and our subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates or change of principal business;
- a provision limiting oil and natural gas derivative financial instruments;
- a requirement that we maintain a ratio of consolidated EBITDAX (as defined in the Oasis Credit Facility) to consolidated Interest Expense (as defined in the Oasis Credit Facility) of no less than 2.5 to 1.0 for the four quarters ended on the last day of each quarter;
- a requirement that we maintain a Current Ratio (as defined in the Oasis Credit Facility) of consolidated current assets (including unused borrowing base committed capacity and with exclusions as described in the Oasis Credit Facility) to consolidated current liabilities (with exclusions as described in the Oasis Credit Facility) of no less than 1.0 to 1.0 as of the last day of any fiscal quarter; and
- if the Aggregate Elected Commitment Amounts (as defined in the Oasis Credit Facility) exceed 85% of the effective borrowing base (“Trigger”), we are required to maintain a ratio of total debt (as defined in the Oasis Credit Facility) to consolidated EBITDAX (as defined in the Oasis Credit Facility) (the “Leverage Ratio”). The Leverage Ratio will be first tested during the quarter in which the Trigger occurs. The Leverage Ratio shall continue to be tested as long as the Aggregate Elected Commitment Amounts exceed 85% of the effective borrowing base, and shall not exceed 4.25 to 1.00 for the first two quarters and 4.00 to 1.00 for each fiscal quarter thereafter.

The Oasis Credit Facility contains customary events of default. If an event of default occurs and is continuing, the Lenders may declare all amounts outstanding under the Oasis Credit Facility to be immediately due and payable.

As of December 31, 2018, we had $468.0 million of borrowings at a weighted average interest rate of 4.2% and $14.0 million of outstanding letters of credit issued under the Oasis Credit Facility, resulting in an unused borrowing base committed capacity of $868.0 million. As of December 31, 2017, we had $70.0 million of borrowings at a weighted average interest rate of 3.1% and $10.5 million of outstanding letters of credit issued under the Oasis Credit Facility, resulting in an unused borrowing base committed capacity of $1,069.5 million. We were in compliance with the financial covenants of the Oasis Credit Facility as of December 31, 2018 and 2017. Given the fluctuation in commodity prices, we continue to closely monitor our financial covenants and do not anticipate a covenant violation in the next twelve months.

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OMP Operating LLC revolving line of credit. OMP has the OMP Credit Facility, which has an overall revolving credit facility of $400.0 million as of December 31, 2018. The OMP Credit Facility has a maturity date of September 25, 2022 and is available to fund working capital and to finance acquisitions and other capital expenditures of OMP. On August 27, 2018, OMP entered into an amendment to its revolving credit facility (the "First Amended OMP Credit Agreement") in order to (i) increase the aggregate amount of commitments from $200.0 million to $250.0 million, (ii) provide for the ability to further increase commitments and (iii) add six new lenders to the bank group. On November 19, 2018, in connection with the OMP Dropdown (see Note 3 – Oasis Midstream Partners LP), and pursuant to the terms of the First Amended OMP Credit Agreement, the aggregate amount of commitments increased from $250.0 million to $400.0 million, and OMP was provided the ability to further increase the borrowing capacity for the OMP Credit Facility to $600.0 million, subject to certain conditions.

The OMP Credit Facility includes a letter of credit sublimit of $10.0 million and a swingline loans sublimit of $10.0 million. All obligations of OMP Operating LLC, as the borrower under the OMP Credit Facility, are unconditionally guaranteed on a joint and several basis by OMP, OMP Operating LLC and Bighorn DevCo LLC.

The OMP Credit Facility includes certain financial covenants as of the end of each fiscal quarter, including a (1) consolidated total leverage ratio, (2) consolidated senior secured leverage ratio and (3) consolidated interest coverage ratio (each covenant as described in the OMP Credit Agreement).

As of December 31, 2018, we had $318.0 million of borrowings outstanding at a weighted average interest rate of 4.2% under the OMP Credit Facility, resulting in an unused borrowing base committed capacity of $82.0 million. As of December 31, 2017, we had $78.0 million of borrowings outstanding at a weighted average interest rate of 3.2% under the OMP Credit Facility, resulting in an unused borrowing base committed capacity of $122.0 million. OMP Operating LLC was in compliance with the financial covenants of the OMP Credit Facility at December 31, 2018 and 2017.

Senior unsecured notes. As of December 31, 2018, our long-term debt includes outstanding senior unsecured note obligations of $1,739.4 million for senior unsecured notes (the "Senior Notes"), including $71.8 million of 6.50% senior unsecured notes due November 1, 2021 (the "2021 Notes"), $901.5 million of 6.875% senior unsecured notes due March 15, 2022 (the "2022 Notes"), $366.1 million of 6.875% senior unsecured notes due January 15, 2023 (the "2023 Notes") and $400.0 million of 6.25% senior unsecured notes due May 1, 2026 (the "2026 Notes").

On May 14, 2018, we completed our offering of $400.0 million in aggregate principal amount of the 2026 Notes. We used the net proceeds of $394.4 million from the 2026 Notes to fund the repurchase of certain outstanding senior notes (the "Tender Offers"), as described below.

On May 25, 2018, we completed the Tender Offers and, as a result of the Tender Offers, we repurchased an aggregate principal amount of $390.6 million of our outstanding Senior Notes, consisting of $31.3 million principal amount of the 7.25% senior unsecured notes due 2019 (the "2019 Notes"), $323.7 million principal amount of the 2021 Notes and $35.6 million principal amount of the 2022 Notes, for an aggregate cost of $402.0 million, including accrued interest and fees.

On May 29, 2018, we paid $23.0 million to redeem all of the remaining outstanding 2019 Notes, which payment consisted of the 100% redemption price plus all accrued and unpaid interest on the 2019 Notes. We financed the redemption with borrowings under the Oasis Credit Facility. As a result of the Tender Offers and the 2019 Notes redemption, we recognized a pre-tax loss of $13.8 million, which was net of unamortized deferred financing costs write-offs of $4.0 million, and is reflected in loss on extinguishment of debt in our Consolidated Statements of Operations for the year ended December 31, 2018. As of December 31, 2018, no 2019 Notes remained outstanding.

Prior to certain dates, we have the option to redeem some or all of the Senior Notes for cash at certain redemption prices equal to a certain percentage of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. We may from time to time seek to retire or purchase our outstanding Senior Notes through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

The indentures governing the Senior Notes restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when our Senior Notes are rated investment grade by both Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no default (as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants. We were in compliance with the terms of the indentures for the Senior Notes as of December 31, 2018.

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Senior unsecured convertible notes. At December 31, 2018, we had $300.0 million of 2.625% senior unsecured convertible notes due September 2023 (the "Senior Convertible Notes"). The Senior Convertible Notes will mature on September 15, 2023 unless earlier converted in accordance with their terms.

We have the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at out election. Our intent is to settle the principal amount of the Senior Convertible Notes in cash upon conversion. Prior to March 15, 2023, the Senior Convertible Notes will be convertible only under the following circumstances: (i) during any calendar quarter commencing after the calendar quarter ending on September 30, 2016 (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the "Measurement Period") in which the trading price per $1,000 principal amount of the Senior Convertible Notes for each trading day of the Measurement Period is less than 98% of the product of the last reported sale price of our common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events. On or after March 15, 2023, the Senior Convertible Notes will be convertible at any time until the second scheduled trading day immediately preceding the September 15, 2023 maturity date. The Senior Convertible Notes will be convertible at an initial conversion rate of 76.3650 shares of our common stock per $1,000 principal amount of the notes, which is equivalent to an initial conversion price of approximately $13.10. The conversion rate will be subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest. In addition, following certain corporate events that occur prior to the maturity date or a notice of redemption, we will increase the conversion rate for a holder who elects to convert the Senior Convertible Notes in connection with such corporate event or redemption in certain circumstances. As of December 31, 2018, none of the contingent conditions allowing holders of the Senior Convertible Notes to convert these notes had been met. In addition, we were in compliance with the terms of the indentures for the Senior Convertible Notes as of December 31, 2018.

Interest on the Senior Notes and the Senior Convertible Notes (collectively, the "Notes") is payable semi-annually in arrears. The Notes are guaranteed on a senior unsecured basis by our material subsidiaries.

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Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2018:

Contractual obligations	Total	Within 1 year	1-3 years	3-5 years	More than 5 years
	Payments due by period				
	(In thousands)				
Senior unsecured notes[1]	$2,039,409	$—	$71,835	$1,567,574	$400,000
Interest payments on senior unsecured notes[1]	584,018	124,690	249,510	147,318	62,500
Borrowings under Oasis Credit Facility[1]	468,000	—	—	468,000	—
Borrowings under OMP Credit Facility[1]	318,000	—	—	318,000	—
Interest payments on borrowings under Oasis Credit Facility[1]	493	493	—	—	—
Interest payments on borrowings under OMP Credit Facility[1]	442	442	—	—	—
Asset retirement obligations[2]	52,450	271	2,117	1,137	48,925
Drilling rig commitments	1,293	1,293	—	—	—
Operating leases[3]	44,362	8,723	13,014	9,491	13,134
Volume commitment agreements[3]	627,960	82,083	180,283	175,198	190,396
Total contractual cash obligations	$4,136,427	$217,995	$516,759	$2,686,718	$714,955

(1) See Note 12 to our consolidated financial statements for a description of our senior unsecured notes, Revolving Credit Facilities and related interest payments. As of December 31, 2018, we had $468.0 million of borrowings and $14.0 million of outstanding letters of credit issued under the Oasis Credit Facility and $318.0 million of borrowings under the OMP Credit Facility.

(2) Amounts represent the present value of estimated costs expected to be incurred in the future to plug, abandon and remediate our oil and gas properties and produced and flowback water disposal wells at the end of their productive lives. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 13 to our consolidated financial statements.

(3) See Note 20 to our consolidated financial statements for a description of our operating leases and volume commitment agreements.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our audited consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments used in preparation of our consolidated financial statements below. See Note 2 to our consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive.

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The provision for DD&A of oil and natural gas properties is calculated using the unit-of-production method. All capitalized well costs and leasehold costs of proved properties are amortized on a unit-of-production basis over the remaining life of proved developed reserves and total proved reserves, respectively, related to the associated field. Natural gas is converted to barrel equivalents at the rate of six thousand cubic feet of natural gas to one barrel of oil. The calculation for the unit-of-production DD&A method takes into consideration estimated future dismantlement, restoration and abandonment costs, which are net of estimated salvage values.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated DD&A unless doing so significantly affects the unit-of-production amortization rate in which case a gain or loss is recognized currently.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated lease acquisition costs. The expensing of the lease acquisition costs is recorded as impairment in our Consolidated Statements of Operations. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Oil and natural gas reserve quantities and standardized measure of future net revenue

Our independent reserve engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. While the SEC rules allow us to disclose proved, probable and possible reserves, we have elected to disclose only proved reserves in this Annual Report on Form 10-K. The SEC's rules define proved reserves as the quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Our independent reserve engineers and technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates are updated annually and consider recent production levels and other technical information about each field. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Periodic revisions to the estimated reserves and related future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data or other economic factors. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Revenue recognition

In the first quarter of 2018, we adopted Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers, and a series of related accounting standards updates incorporated into GAAP as Accounting Standards Codification Topic 606 ("ASC 606") using the modified retrospective method. The unit of account in ASC 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. ASC 606 requires that a contract’s transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) the performance obligation is satisfied.

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Oil and gas revenues from our interests in producing wells are recognized when we satisfy a performance obligation by transferring control of a product to a customer. Substantially all of our production is sold to purchasers under short-term (less than twelve months) contracts at market-based prices. The sales prices for oil and natural gas are adjusted for transportation and other related deductions. These deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these revenue deductions are adjusted to reflect actual charges based on third-party documents. Since there is a ready market for oil and natural gas, we sell the majority of our production soon after it is produced at various locations. As a result, we maintain a minimum amount of product inventory in storage.

Our purchased oil and gas sales are derived from the sale of oil and gas purchased from a third party. Revenues and expenses from these sales and purchases are generally recorded on a gross basis, as we act as a principal in these transactions by assuming control of the purchased oil or gas before it is transferred to the customer. In certain cases, we enter into sales and purchases with the same counterparty in contemplation of one another, and these transactions are recorded on a net basis in accordance with Accounting Standards Codification 845, Nonmonetary Transactions.

Midstream revenues consist of revenues from midstream services provided through OMS, including (i) crude oil gathering, stabilization, blending, storage and transportation, (ii) natural gas gathering, gas lift, compression and processing, (iii) produced and flowback water gathering and disposal and (iv) freshwater supply and distribution. Midstream revenues are earned through fee-based arrangements, under which we receive fees for midstream services it provides to customers and recognizes revenue based upon the transaction price at month-end under the right to invoice practical expedient, or through purchase arrangements, under which we take control of the product prior to sale and act as the principal in the transaction, and therefore, recognize revenues and expenses on a gross basis. Well services revenues result from well services, product sales and equipment rentals provided by OWS primarily for OPNA's operated wells. Midstream and well services revenues are recognized when services have been performed or related volumes or products have been delivered. The revenues related to OPNA's working interests are eliminated in consolidation, and only the revenues related to other working interest owners in OPNA's wells are included in our Consolidated Statements of Operations.

Impairment of proved properties

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected undiscounted future cash flows of our oil and natural gas properties by field and compare such undiscounted future cash flows to the carrying amount of the oil and natural gas properties in the applicable field to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved oil and natural gas properties will be recorded. Please see "Overview" for a discussion of potential future impairment charges.

Impairment of unproved properties

The assessment of unproved properties to determine any possible impairment requires significant judgment. We assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage.

We recognize impairment expense for unproved properties at the time when the lease term has expired or sooner based on management's periodic assessments. We consider the following factors in our assessment of the impairment of unproved properties:

- the remaining amount of unexpired term under our leases;
- our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that may be close to expiration;

- our ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- our ability to convey partial mineral ownership to other companies in exchange for their drilling of leases; and
- our evaluation of the continuing successful results from the application of completion technology in the Bakken and Three Forks formations in the Williston Basin and the Bone Spring and Wolfcamp formations in the Delaware Basin by us or by other operators in areas adjacent to or near our unproved properties.

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Business combinations

We account for business combinations under the acquisition method of accounting. Accordingly, we recognize amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. Transaction and integration costs associated with business combinations are expensed as incurred.

We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of proved and unproved oil and natural gas properties. The fair values of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of reserves, future operating and development costs, future commodity prices and a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of oil and natural gas properties within the same regions, and use that data as a proxy for fair market value; for example, the amount a willing buyer and seller would enter into in exchange for such properties.

Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill. Any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain on bargain purchase. Deferred taxes are recorded for any differences between the assigned values and the tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Asset retirement obligations

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred and can be reasonably estimated with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The asset retirement obligation ("ARO") represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period, and the capitalized costs are amortized on the unit-of-production method. The accretion expense is recorded as a component of depreciation, depletion and amortization in our Consolidated Statements of Operations.

Some of our midstream assets, including certain pipelines and our natural gas processing plants, have contractual or regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities, when the assets are abandoned. We are not able to reasonably estimate the fair value of the asset retirement obligations for these assets because the settlement dates are indeterminable given our expected continued use of the assets with proper maintenance. We will record asset retirement obligations for these assets in the periods in which the settlement dates are reasonably determinable.

We determine the ARO by calculating the present value of estimated future cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to future revisions, which could result in an increase to the existing ARO liability and could ultimately result in a higher potential impact on our operations and cash flows for settlement charges. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Derivatives

We record all derivative instruments on the Consolidated Balance Sheets as either assets or liabilities measured at their estimated fair value. The significant inputs used to estimate fair value are crude oil prices, volatility, skew, discount rate and the contract terms of the derivative instruments. Derivative assets and liabilities arising from derivative contracts with the same counterparty are reported on a net basis, as all counterparty contracts provide for net settlement. We have not designated any derivative instruments as hedges for accounting purposes, and we do not enter into such instruments for speculative trading purposes. Gains and losses from valuation changes in commodity derivative instruments are reported under other income (expense) in our Consolidated Statements of Operations. Our cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on our derivative instruments and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled. Cash settlements are reflected as investing activities in our Consolidated Statements of Cash Flows.

Equity-based compensation

Restricted stock awards. We recognize compensation expense for all restricted stock awards made to employees and directors. Equity-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense on a straight-line basis over the requisite service period, which is generally the vesting period. The fair value of restricted stock grants is based on the value of our common stock on the date of grant. Any such changes could result in different valuations and thus impact the amount of equity-based compensation expense recognized. Equity-based compensation expense recorded for restricted stock awards is included in general and administrative expenses on our Consolidated Statements of Operations. Forfeitures associated with restricted stock awards granted are accounted for when they occur.

Performance share units. We recognize compensation expense for our performance share units ("PSUs") granted to our officers. The fair value of the PSUs is based on the calculation derived from a Monte Carlo simulation model. The Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probable assessment (see Note 15 to our consolidated financial statements for a description of the inputs used in this model). Equity-based compensation expense recorded for PSUs is included in general and administrative expenses on our Consolidated Statements of Operations. Forfeitures associated with awards granted under PSUs are accounted for when they occur.

OMP Phantom Unit Awards. We recognize compensation expense for all OMP phantom unit awards (collectively, the "OMP Phantom Unit Awards," and each an "OMP Phantom Unit") granted to employees. The OMP Phantom Unit Awards are accounted for as liability-classified awards since the awards will settle in cash. The OMP Phantom Unit Awards vest in equal amounts each year over a three-year period, and compensation expense will be recognized over the requisite service period and is included in general and administrative expenses on the Company's Consolidated Statements of Operations. Compensation cost is remeasured each reporting period at fair value based upon the closing price of a publicly traded common unit. The Company will directly pay, or will reimburse OMP, for the cash settlement amount of these awards. Forfeitures associated with awards granted under the OMP LTIP are accounted for when they occur.

Income taxes

Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP, which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there may be transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Recent accounting pronouncements

Leases. In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases ("ASU 2016-02"), which established a right-of-use ("ROU") model that requires a lessee to recognize an operating lease asset and lease liability on the balance sheet, with the exception of short-term leases (as described below). Accounting Standards

Codification 842, Leases (“ASC 842”), was subsequently amended by Accounting Standards Update No. 2018-01, Land easement practical expedient for transition to Topic 842 (“ASU 2018-01”); Accounting Standards Update No. 2018-10, Codification Improvements to Topic 842; and Accounting Standards Update No. 2018-11, Targeted Improvements. The new standard is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The effective date and transition requirements for the amendments are the same as the effective date for ASU 2016-02. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application. An entity may choose to use either (i) its effective date or (ii) the beginning of the earliest comparative period presented in the financial statements as its date of initial application.

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We will adopt the new standard as of January 1, 2019 using the required modified retrospective approach and plan to elect the option to recognize a cumulative effect adjustment of initially applying the guidance to the opening balance of retained earnings in the period of adoption, rather than recognizing in the earliest period presented. Prior period amounts will not be adjusted.

ASU 2018-01 provides a number of optional practical expedients in transition. We expect to elect the package of practical expedients, which permits us not to reassess under the new standard prior conclusions about lease identification, lease classification and initial direct costs; the use-of hindsight practical expedient; the practical expedient pertaining to land easements, which provides an option to not evaluate under ASC 842 existing or expired land easements that were previously accounted for as leases under Accounting Standards Codification 840, Leases; and the practical expedient pertaining to combining lease and non-lease components. In addition, under the new standard, an entity may elect not to apply the recognition requirements of ASC 842 to short-term leases, which are leases with terms of one year or less. We expect to make this election, and as such, recognition of lease payments for short-term leases will be recognized in net income on a straight line basis.

We expect this new standard will have a material effect on the consolidated financial statements. While we continue to assess all of the effects of adoption, we believe the most significant effects relate to (i) the recognition of new ROU assets and lease liabilities on the consolidated balance sheet and (ii) providing significant new disclosures about our leasing activities. The new ROU assets and lease liabilities, which will be recognized on the consolidated balance sheet, consist primarily of offices, man-camps, rigs and vehicles.

We plan to modify our business processes and controls to support the adoption of the new standard, including implementing a new lease accounting software to assess the portfolio of leases, assist in the quantification of the expected impact on the consolidated financial statements and facilitate the calculations of the related accounting entries and disclosures. We do not expect a significant change in leasing activities as a result of this adoption.

Financial instruments. In August 2018, the FASB issued Accounting Standards Update No. 2018-13, Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement ("ASU 2018-13"), which improves the effectiveness of the disclosure requirements for fair value measurements. The changes affect all companies that are required to include fair value measurement disclosures. ASU 2018-13 is effective for fiscal years beginning after December 15, 2019, including interim periods within those years. An entity is permitted to early adopt the removed or modified disclosures upon the issuance of ASU 2018-13 and may delay adoption of the additional disclosures until their effective date. We do not expect the adoption of this guidance to have an impact on our financial position, cash flows or results of operations, but it may result in changes to our disclosures.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2018, 2017 and 2016. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy, and in the past, we have tended to experience inflationary pressure on the cost of midstream and oilfield services and equipment as increasing oil and natural gas prices increased drilling activity in our areas of operations. We expect service costs to increase in 2018 due to higher demand resulting from the recent improvement in oil prices.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements as defined by the SEC. In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with GAAP. See "Obligations and commitments" above and Note 20 to our consolidated financial statements for a description of our commitments and contingencies.

Non-GAAP Financial Measures

E&P Cash G&A, Cash Interest, Adjusted EBITDA, Free Cash Flow, Adjusted Net Income (Loss) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share are supplemental non-GAAP financial measures that are used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. These non-GAAP measures should not be considered in isolation or as a substitute for interest expense, net income (loss), operating income (loss), net cash provided by (used in) operating activities, earnings (loss) per share or any other measures prepared under GAAP. Because Cash Interest, Adjusted EBITDA, Free Cash Flow, Adjusted Net Income (Loss) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share exclude some but not all items that affect net income (loss) and may vary among companies, the amounts presented may not be comparable to similar metrics of other companies.

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E&P Cash G&A

We define E&P Cash G&A as the total general and administrative expenses included in our exploration and production segment less non-cash equity-based compensation expenses included in our exploration and production segment. E&P Cash G&A is not a measure of general and administrative expenses as determined by GAAP. Management believes that the presentation of E&P Cash G&A provides useful additional information to investors and analysts to assess our operating costs in comparison to peers without regard to equity-based compensation programs, which can vary substantially from company to company.

The following table presents a reconciliation of the GAAP financial measure of general and administrative expenses included in our exploration and production segment to the non-GAAP financial measure of E&P Cash G&A for the periods presented:

Exploration and Production

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
General and administrative expenses	$102,482	$77,560	$78,995
Equity-based compensation expenses	(27,910)	(25,436)	(23,346)
E&P Cash G&A	$74,572	$52,124	$55,649

Cash Interest

We define Cash Interest as interest expense plus capitalized interest less amortization and write-offs of deferred financing costs and debt discounts included in interest expense. Cash Interest is not a measure of interest expense as determined by GAAP. Management believes that the presentation of Cash Interest provides useful additional information to investors and analysts for assessing the interest charges incurred on our debt, excluding non-cash amortization, and our ability to maintain compliance with our debt covenants.

The following table presents a reconciliation of the GAAP financial measure of interest expense to the non-GAAP financial measure of Cash Interest for the periods presented:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Interest expense	$159,085	$146,837	$140,305
Capitalized interest	17,226	12,797	16,848
Amortization of deferred financing costs	(7,590)	(6,907)	(9,757)
Amortization of debt discount	(11,120)	(10,080)	(2,709)
Cash Interest	$157,601	$142,647	$144,687

Adjusted EBITDA and Free Cash Flow

We define Adjusted EBITDA as earnings (loss) before interest expense, income taxes, DD&A, exploration expenses and other similar non-cash or nonrecurring charges. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Management believes that the presentation of Adjusted EBITDA provides useful additional information to investors and analysts for assessing our results of operations, financial performance and our ability to generate cash from our business operations without regard to our financing methods or capital structure coupled with our ability to maintain compliance with our debt covenants.

We define Free Cash Flow as Adjusted EBITDA less Cash Interest and capital expenditures, excluding capitalized interest. Free Cash Flow is not a measure of net income (loss) or cash flows as determined by GAAP. Management believes that the presentation of Free Cash Flow provides useful additional information to investors and analysts for assessing our financial performance as compared to our peers and our ability to generate cash from our business operations after interest and capital spending. In addition, Free Cash Flow excludes changes in operating assets and liabilities that relate to the timing of cash receipts and disbursements, which we may not control, and changes in operating assets and liabilities may not relate to the period in which the operating activities occurred.

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The following table presents reconciliations of the GAAP financial measures of net income (loss) including non-controlling interests and net cash provided by operating activities to the non-GAAP financial measures of Adjusted EBITDA and Free Cash Flow for the periods presented:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Net income (loss) including non-controlling interests	$(19,500)	$127,446	$(243,016)
(Gain) loss on sale of properties	(28,587)	(1,774)	1,303
(Gain) loss on extinguishment of debt	13,848	—	(4,741)
Net (gain) loss on derivative instruments	(28,457)	71,657	105,317
Derivative settlements(1)	(213,528)	(8,264)	121,977
Interest expense, net of capitalized interest	159,085	146,837	140,305
Depreciation, depletion and amortization	636,296	530,802	476,331
Impairment	384,228	6,887	4,684
Exploration expenses	27,432	11,600	1,785
Equity-based compensation expenses	29,273	26,534	24,103
Income tax benefit	(5,843)	(203,304)	(128,538)
Other non-cash adjustments	4,435	(745)	790
Adjusted EBITDA	958,682	707,676	500,300
Adjusted EBITDA attributable to non-controlling interests	21,703	3,904	—
Adjusted EBITDA attributable to Oasis	936,979	703,772	500,300
Cash Interest	(157,601)	(142,647)	(144,687)
Capital expenditures(2)	(2,203,453)	(836,204)	(1,181,527)
Capitalized interest	17,226	12,797	16,848
Free Cash Flow	$(1,406,849)	$(262,282)	$(809,066)
Net cash provided by operating activities	$996,421	$507,876	$228,018
Derivative settlements(1)	(213,528)	(8,264)	121,977
Interest expense, net of capitalized interest	159,085	146,837	140,305
Exploration expenses	27,432	11,600	1,785
Deferred financing costs amortization and other	(29,057)	(18,311)	(14,334)
Current tax expense	23	(421)	—
Changes in working capital	13,871	69,104	21,759
Other non-cash adjustments	4,435	(745)	790
Adjusted EBITDA	958,682	707,676	500,300
Adjusted EBITDA attributable to non-controlling interests	21,703	3,904	—
Adjusted EBITDA attributable to Oasis	936,979	703,772	500,300
Cash Interest	(157,601)	(142,647)	(144,687)
Capital expenditures(2)	(2,203,453)	(836,204)	(1,181,527)
Capitalized interest	17,226	12,797	16,848
Free Cash Flow	$(1,406,849)	$(262,282)	$(809,066)

(1) Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

(2) Capital expenditures (including acquisitions) reflected in the table above differ from the amounts shown in the statements of cash flows in our consolidated financial statements because amounts reflected in the table include changes in accrued liabilities from the previous reporting period for capital expenditures, while the amounts presented in the statement of cash flows are presented on a cash basis. Acquisitions totaled $951.9 million, $54.0

million and $781.5 million for the years ended December 31, 2018, 2017 and 2016, respectively. In addition, capital expenditures

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(including acquisitions) reflected in the table includes consideration paid through the issuance of common stock in connection with the Permian Basin Acquisition for the year ended December 31, 2018. See Note 10 to our consolidated financial statements for more information on the Permian Basin Acquisition.

The following tables present reconciliations of the GAAP financial measure of income (loss) before income taxes including non-controlling interests to the non-GAAP financial measure of Adjusted EBITDA for our three reportable business segments on a gross basis for the periods presented:

Exploration and Production

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Loss before income taxes including non-controlling interests	$(167,292)	$(179,129)	$(436,469)
(Gain) loss on sale of properties	(38,188)	(1,774)	1,661
(Gain) loss on extinguishment of debt	13,848	—	(4,741)
Net (gain) loss on derivative instruments	(28,457)	71,657	105,317
Derivative settlements[1]	(213,528)	(8,264)	121,977
Interest expense, net of capitalized interest	156,742	146,818	140,305
Depreciation, depletion and amortization	618,402	519,853	467,894
Impairment	384,228	6,887	2,253
Exploration expenses	27,432	11,600	1,785
Equity-based compensation expenses	27,910	25,436	23,346
Other non-cash adjustments	4,331	(812)	718
Adjusted EBITDA	$785,428	$592,272	$424,046

(1) Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

Midstream Services

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Income before income taxes including non-controlling interests	$141,001	$102,340	$68,394
(Gain) loss on sale of properties	9,622	—	(358)
Interest expense, net of capitalized interest	2,343	19	—
Depreciation, depletion and amortization	29,282	15,999	8,525
Impairment	—	—	2,431
Equity-based compensation expenses	1,547	1,461	911
Other non-cash adjustments	—	—	10
Adjusted EBITDA	$183,795	$119,819	$79,913

Well Services

	Year Ended December 31,		
	2018	2017	2016
	(In thousands)		
Income before income taxes including non-controlling interests	$31,023	$15,091	$3,471
Depreciation, depletion and amortization	15,698	12,939	14,892
Equity-based compensation expenses	1,588	1,264	1,515
Other non-cash adjustments	104	67	62
Adjusted EBITDA	$48,413	$29,361	$19,940

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Adjusted Net Income (Loss) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share

We define Adjusted Net Income (Loss) Attributable to Oasis as net income (loss) after adjusting for (1) the impact of certain non-cash items, including non-cash changes in the fair value of derivative instruments, impairment and other similar non-cash charges, or non-recurring items, (2) the impact of net income attributable to non-controlling interests and (3) the non-cash and non-recurring items' impact on taxes based on our effective tax rate applicable to those adjusting items, excluding net income attributable to non-controlling interests, in the same period. Adjusted Net Income (Loss) Attributable to Oasis is not a measure of net income (loss) as determined by GAAP. We define Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share as Adjusted Net Income (Loss) Attributable to Oasis divided by diluted weighted average shares outstanding. Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share is not a measure of diluted earnings (loss) as determined by GAAP. Management believes that the presentation of Adjusted Net Income (Loss) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share provides useful additional information to investors and analysts for evaluating our operational trends and performance in comparison to our peers. This measure is more comparable to earnings estimates provided by securities analysts, and charges or amounts excluded cannot be reasonably estimated and are excluded from guidance provided by us.

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The following table presents reconciliations of the GAAP financial measure of net income (loss) attributable to Oasis to the non-GAAP financial measure of Adjusted Net Income (Loss) Attributable to Oasis and the GAAP financial measure of diluted earnings (loss) attributable to Oasis per share to the non-GAAP financial measure of Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share for the periods presented:

	Year Ended December 31,		
	2018	2017	2016
	(In thousands, except per share data)		
Net income (loss) attributable to Oasis	$(35,296)	$123,796	$(243,016)
Tax reform rate change adjustments	—	(171,900)	—
(Gain) loss on sale of properties	(28,587)	(1,774)	1,303
(Gain) loss on extinguishment of debt	13,848	—	(4,741)
Net (gain) loss on derivative instruments	(28,457)	71,657	105,317
Derivative settlements[1]	(213,528)	(8,264)	121,977
Impairment	384,228	6,887	4,684
Amortization of deferred financing costs	7,591	6,907	9,757
Amortization of debt discount	11,120	10,080	2,709
Other non-cash adjustments	4,435	(745)	790
Tax impact[2]	(35,759)	(31,696)	(90,480)
Adjusted Net Income (Loss) Attributable to Oasis	$79,595	$4,948	$(91,700)
Diluted earnings (loss) attributable to Oasis per share	$(0.11)	$0.52	$(1.32)
Tax reform rate change adjustments	—	(0.72)	—
(Gain) loss on sale of properties	(0.09)	(0.01)	0.01
(Gain) loss on extinguishment of debt	0.04	—	(0.03)
Net (gain) loss on derivative instruments	(0.09)	0.30	0.57
Derivative settlements[1]	(0.69)	(0.03)	0.66
Impairment	1.24	0.03	0.03
Amortization of deferred financing costs	0.02	0.03	0.05
Amortization of debt discount	0.04	0.04	0.01
Other non-cash adjustments	0.01	—	—
Tax impact[2]	(0.11)	(0.14)	(0.48)
Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share	$0.26	$0.02	$(0.50)
Diluted weighted average shares outstanding[3]	310,860	237,875	183,615
Effective tax rate applicable to adjustment items	23.7%	37.4%	37.4%

(1) Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

(2) The tax impact is computed utilizing our effective tax rate applicable to the adjustments for certain non-cash and non-recurring items. The tax impact was not computed for the tax reform rate change adjustments.

(3) We included 3,379,000 and 2,889,000 of unvested stock awards for the years ended December 31, 2018 and 2017, respectively, in computing Adjusted Diluted Income Attributable to Oasis Per Share due to the dilutive effect under the treasury stock method. No unvested stock awards were included in computing Adjusted Diluted Loss Attributable to Oasis Per Share for the year ended December 31, 2016 because the effect was anti-dilutive due to Adjusted Net Loss Attributable to Oasis.

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Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management, including the use of derivative instruments.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas, natural gas liquids, and oil prices, and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

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

We utilize derivative financial instruments to manage risks related to changes in oil and natural gas prices. Our crude oil contracts will settle monthly based on the average NYMEX West Texas Intermediate crude oil index price (“NYMEX WTI”), the average Intercontinental Exchange, Inc. Brent crude oil index price (“ICE Brent”), the average Argus WTI Midland crude oil index price (“Midland”) and the average Argus WTI Houston crude oil index price. Our natural gas contracts will settle monthly based on the average NYMEX Henry Hub natural gas index price (“NYMEX HH”) and the average Inside FERC Northern Natural Gas Ventura natural gas index price (“IF NNG Ventura”).

As of December 31, 2018, we utilized fixed price swaps, basis swaps and two-way and three-way costless collars to reduce the volatility of oil and natural gas prices on a significant portion of its future expected oil and natural gas production. Our fixed price swaps are comprised of a sold call and a purchased put established at the same price (both ceiling and floor), which we will receive for the volumes under contract. A basis swap transaction has an established fixed basis differential corresponding to two floating index prices. Depending on the difference of the two floating index prices in relation to the fixed basis differential, we either receive an amount from its counterparty, or pay an amount to its counterparty, equal to the difference multiplied by the contract volume. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be the NYMEX index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract.

We recognize all derivative instruments at fair value. The credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on our Consolidated Balance Sheets. Derivative assets and liabilities arising from our derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement.

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The following is a summary of our outstanding commodity derivative instruments as of December 31, 2018:

Commodity	Settlement Period	Derivative Instrument	Index	Volumes		Weighted Average Prices Fixed Price Swaps	Basis Swaps	Sub-Floor	Floor	Ceiling	Fair V Asse (Liab (In th
Crude oil	2019	Fixed price swaps	NYMEX WTI	5,690,500	Bbl	$53.63					$33,8
Crude oil	2019	Basis swaps	NYMEX WTI-ICE BRENT	424,000	Bbl		$(9.68)				673
Crude oil	2019	Basis swaps	Midland-NYMEX WTI	605,000	Bbl		$(7.19)				(865
Crude oil	2019	Two-way collars	NYMEX WTI	3,937,500	Bbl				$58.47	$77.03	48,32
Crude oil	2019	Three-way collars	NYMEX WTI	3,702,000	Bbl			$40.49	$50.94	$67.97	16,52
Crude oil	2020	Fixed price swaps	NYMEX WTI	403,000	Bbl	$53.47					1,928
Crude oil	2020	Two-way collars	NYMEX WTI	341,000	Bbl				$58.18	$77.65	3,982
Crude oil	2020	Three-way collars	NYMEX WTI	310,000	Bbl			$40.00	$50.50	$67.10	1,035
Natural gas	2019	Fixed price swaps	NYMEX HH	6,446,000	MMBtu	$3.15					1,303
Natural gas	2019	Basis swaps	IF NNG VENTURA-NYMEX HH	4,525,000	MMBtu		$0.02				40
											$106

A 10% increase in crude oil prices would decrease the fair value of our derivative position by approximately $46.3 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $47.7 million.

Interest rate risk. At December 31, 2018, we had (i) $71.8 million of senior unsecured notes at a fixed cash interest rate of 6.50% per annum, (ii) $1,267.6 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum, (iii) $300.0 million of senior unsecured convertible notes at a fixed cash interest rate of 2.625% per annum outstanding and (iv) $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.25% per annum.

At December 31, 2018, we had $468.0 million of borrowings and $14.0 million of outstanding letters of credit issued under the Oasis Credit Facility, which were subject to varying rates of interest based on (i) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (ii) whether the loan is a LIBOR loan or a domestic bank prime interest rate loan (defined in each of the Revolving Credit Facilities as an Alternate Based Rate or "ABR" loan). At December 31, 2018, the outstanding borrowings under the Oasis Credit Facility bore interest at LIBOR plus a 1.75% margin. On a quarterly basis, we also pay a commitment fee that can range from 0.375% to 0.500% on the average amount of borrowing base capacity not utilized during the quarter and fees calculated on the average amount of letter of credit balances outstanding during the quarter.

At December 31, 2018, we had $318.0 million of borrowings issued under the OMP Credit Facility, which were subject to a per annum interest rate equal to the applicable margin (as described below) plus (i) with respect to Eurodollar Loans, the Adjusted LIBO Rate (as defined in the OMP Credit Agreement) or (ii) with respect to ABR loans, the greatest of (A) the Prime Rate in effect on such day, (B) the Federal Funds Effective Rate in effect on such day plus 1/2 of 1.00% or (C) the Adjusted LIBO Rate for a one-month interest period on such day plus 1.00% (each as defined in the OMP Credit Agreement). The applicable margin for borrowings under the OMP Credit Facility is based on OMP's most recently tested consolidated total leverage ratio and varies from (a) in the case of Eurodollar Loans, 1.75% to 2.75%, and (b) in the case of ABR loans or swingline loans, 0.75% to 1.75%. The unused portion of the OMP Credit Facility is subject to a commitment fee ranging from 0.375% to 0.500%. At December 31, 2018, the outstanding borrowings under the OMP Credit Facility bore interest at LIBOR plus a 1.75% margin.

We do not currently, but may in the future, utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to debt issued under the Oasis Credit Facility or the OMP Credit Facility. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

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Counterparty and customer credit risk. Joint interest receivables arise from billing entities which own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we choose to drill. We have limited ability to control participation in our wells. For the year ended December 31, 2018, we recorded $1.5 million in bad debt expense as a result of our assessment that it is probable certain receivables may not be collected. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

We monitor our exposure to counterparties on oil and natural gas sales primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's credit worthiness. We have not generally required our counterparties to provide collateral to secure oil and natural gas sales receivables owed to us. Historically, our credit losses on oil and natural gas sales receivables have been immaterial.

In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. However, in order to mitigate the risk of nonperformance, we only enter into derivative contracts with counterparties that are high credit-quality financial institutions. Most of the counterparties on our derivative instruments currently in place are Lenders under the Oasis Credit Facility with investment grade ratings. We are likely to enter into any future derivative instruments with these or other Lenders under the Oasis Credit Facility, which also carry investment grade ratings. This risk is also managed by spreading our derivative exposure across several institutions and limiting the volumes placed under individual contracts. Furthermore, the agreements with each of the counterparties on our derivative instruments contain netting provisions. As a result of these netting provisions, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative asset position of $106.9 million and a net derivative liability position of $0.1 million at December 31, 2018.

As permitted under our investments policy, we may purchase commercial paper instruments from high credit quality counterparties. These counterparties may include issuers in a variety of industries including the domestic and foreign financial sector. This risk is managed by our investment policy including minimum credit ratings thresholds and maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers failing to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If an issuer fails to repay us at maturity from commercial paper proceeds, it could take a significant amount of time to recover a portion of or all of the assets originally invested. Our commercial paper balance was $36,000 at December 31, 2018.

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Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Oasis Petroleum Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Oasis Petroleum Inc. and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO because a material weakness in internal control over financial reporting existed as of that date related to the ineffective design and maintenance of controls over the presentation and disclosure of certain crude oil purchase and sale arrangements included in oil and gas revenue, purchased oil and gas sales and purchased oil and gas expenses and the related accounts receivable and accrued liabilities accounts.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in Management's report on internal control over financial reporting appearing under Item 9A. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the 2018 consolidated financial statements, and our opinion regarding the effectiveness of the Company's internal control over financial reporting does not affect our opinion on those consolidated financial statements.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's report referred to above. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the

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company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP
Houston, Texas
March 1, 2019
We have served as the Company's auditor since 2007.

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Oasis Petroleum Inc.
Consolidated Balance Sheets

	December 31, 2018	2017
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 22,190	$ 16,720
Accounts receivable, net	387,602	371,379
Inventory	33,128	19,367
Prepaid expenses	10,997	7,631
Derivative instruments	99,930	344
Intangible assets, net	125	—
Other current assets	183	193
Total current assets	554,155	415,634
Property, plant and equipment		
Oil and gas properties (successful efforts method)	8,912,189	7,838,955
Other property and equipment	1,151,772	868,746
Less: accumulated depreciation, depletion, amortization and impairment	(3,036,852)	(2,534,215)
Total property, plant and equipment, net	7,027,109	6,173,486
Derivative instruments	6,945	9
Long-term inventory	12,260	12,200
Other assets	25,673	21,600
Total assets	$ 7,626,142	$ 6,622,929
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 20,166	$ 13,370
Revenues and production taxes payable	216,695	213,995
Accrued liabilities	331,651	244,279
Accrued interest payable	38,040	38,963
Derivative instruments	84	115,716
Advances from joint interest partners	5,140	4,916
Other current liabilities	—	40
Total current liabilities	611,776	631,279
Long-term debt	2,735,276	2,097,606
Deferred income taxes	300,055	305,921
Asset retirement obligations	52,384	48,511
Derivative instruments	20	19,851
Other liabilities	7,751	6,182
Total liabilities	3,707,262	3,109,350
Commitments and contingencies (Note 20)		
Stockholders' equity		
Common stock, $0.01 par value: 900,000,000 and 450,000,000 shares authorized at December 31, 2018 and December 31, 2017, respectively; 320,469,049 shares issued and 318,377,161 shares outstanding at December 31, 2018 and 270,627,014 shares issued and 269,295,466 shares outstanding at December 31, 2017	3,157	2,668
Treasury stock, at cost: 2,091,888 and 1,331,548 shares at December 31, 2018 and December 31, 2017, respectively	(29,025)	(22,179)
Additional paid-in capital	3,077,755	2,677,217

Retained earnings	682,689	717,985
Oasis share of stockholders’ equity	3,734,576	3,375,691
Non-controlling interests	184,304	137,888
Total stockholders’ equity	3,918,880	3,513,579
Total liabilities and stockholders’ equity	$ 7,626,142	$ 6,622,929

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

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Oasis Petroleum Inc.
Consolidated Statements of Operations

	Year Ended December 31,		
	2018	2017	2016
	(In thousands, except per share data)		
Revenues			
Oil and gas revenues	$1,590,024	$1,034,634	$625,233
Purchased oil and gas sales	551,808	133,542	10,272
Midstream revenues	119,040	72,752	35,406
Well services revenues	61,075	52,791	33,754
Total revenues	2,321,947	1,293,719	704,665
Operating expenses			
Lease operating expenses	193,912	177,134	135,444
Midstream operating expenses	31,912	17,589	9,003
Well services operating expenses	41,200	37,228	20,675
Marketing, transportation and gathering expenses	107,193	55,740	30,108
Purchased oil and gas expenses	554,307	134,615	10,258
Production taxes	133,696	88,133	56,565
Depreciation, depletion and amortization	636,296	530,802	476,331
Exploration expenses	27,432	11,600	1,785
Impairment	384,228	6,887	4,684
General and administrative expenses	121,346	91,797	89,342
Total operating expenses	2,231,522	1,151,525	834,195
Gain (loss) on sale of properties	28,587	1,774	(1,303)
Operating income (loss)	119,012	143,968	(130,833)
Other income (expense)			
Net gain (loss) on derivative instruments	28,457	(71,657)	(105,317)
Interest expense, net of capitalized interest	(159,085)	(146,837)	(140,305)
Gain (loss) on extinguishment of debt	(13,848)	—	4,741
Other income (expense)	121	(1,332)	160
Total other expense	(144,355)	(219,826)	(240,721)
Loss before income taxes	(25,343)	(75,858)	(371,554)
Income tax benefit	5,843	203,304	128,538
Net income (loss) including non-controlling interests	(19,500)	127,446	(243,016)
Less: Net income attributable to non-controlling interests	15,796	3,650	—
Net income (loss) attributable to Oasis	$(35,296)	$123,796	$(243,016)
Earnings (loss) attributable to Oasis per share:			
Basic (Note 17)	$(0.11)	$0.53	$(1.32)
Diluted (Note 17)	(0.11)	0.52	(1.32)
Weighted average shares outstanding:			
Basic (Note 17)	307,480	234,986	183,615
Diluted (Note 17)	307,480	237,875	183,615

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

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Oasis Petroleum Inc.
Consolidated Statements of Changes in Stockholders' Equity

	Attributable to Oasis							
	Common Stock		Treasury Stock		Additional Paid-in-Capital	Retained Earnings (Deficit)	Non-controlling Interests	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
	(In thousands)							
Balance as of December 31, 2015	139,076	$ 1,376	508	$ (13,620)	$ 1,497,065	$ 834,521	$ —	$ 2,319,342
Issuance of common stock, net of offering costs	94,300	943	—	—	765,727	—	—	766,670
Equity-based compensation	3,317	12	—	—	25,759	—	—	25,771
Equity component of senior unsecured convertible notes, net	—	—	—	—	56,720	—	—	56,720
Treasury stock - tax withholdings	(349)	—	349	(2,330)	—	—	—	(2,330)
Net loss	—	—	—	—	—	(243,016)	—	(243,016)
Balance as of December 31, 2016	236,344	2,331	857	(15,950)	2,345,271	591,505	—	2,923,157
Cumulative-effect adjustment for adoption of ASU 2016-09 (Note 14)	—	—	—	—	2,040	2,684	—	4,724
Fees (2016 issuance of common stock)	—	—	—	—	(55)	—	—	(55)
Issuance of common stock, net of offering costs	32,000	320	—	—	301,871	—	—	302,191
Equity-based compensation	1,426	17	—	—	28,090	—	53	28,160
Issuance of Oasis Midstream common units, net of offering costs	—	—	—	—	—	—	134,185	134,185
Treasury stock - tax withholdings	(475)	—	475	(6,229)	—	—	—	(6,229)
Net income	—	—	—	—	—	123,796	3,650	127,446
Balance as of December 31, 2017	269,295	2,668	1,332	(22,179)	2,677,217	717,985	137,888	3,513,579
Permian Basin Acquisition issuance	46,000	460	—	—	370,760	—	—	371,220
Other (2017 issuance of common stock and Oasis Midstream common units)	—	—	—	—	(881)	—	(125)	(1,006)
Equity-based compensation	3,842	29	—	—	30,659	—	356	31,044
Issuance of Oasis Midstream common units, net of offering costs	—	—	—	—	—	—	44,503	44,503
Distributions to non-controlling interest owners	—	—	—	—	—	—	(14,114)	(14,114)
	(760)	—	760	(6,846)	—	—	—	(6,846)

Treasury stock - tax withholdings								
Net income (loss)	—	—	—	—	—	(35,296)	15,796	(19,500)
Balance as of December 31, 2018	318,377							