UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2019

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:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.01 per share	OAS	The Nasdaq Stock Market LLC

Securities Registered Pursuant to Section 12(g) of the Act:

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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	☒	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 ☒

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: $1,791,664,921

Number of shares of registrant's common stock outstanding as of February 19, 2020: 323,926,171

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement for its 2020 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2019, are incorporated by reference into Part III of this report for the year ended December 31, 2019.

OASIS PETROLEUM INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2019

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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. In particular, the factors discussed below and detailed under "Item 1A. Risk Factors" could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

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 crude 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 crude oil and natural gas, both in the Williston and Delaware Basins and other regions in the United States;
- property acquisitions and divestitures;
- 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 strategic tactics, budget, projections, execution of business plan and operating results;
- cash flows and liquidity;
- crude 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 crude oil and natural gas industry;
- counterparty credit risk;
- environmental liabilities;
- governmental regulation and the taxation of the crude oil and natural gas industry;
- developments in crude 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; 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. Some of the key factors which could cause actual results to vary from our expectations include changes in crude 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 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, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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 crude 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 gas properties located in the North Dakota and Montana regions of the Williston Basin and the Texas region of the Delaware Basin, respectively. In addition to our exploration and production segment, we also operate a midstream business segment through Oasis Midstream Partners LP (Nasdaq: OMP) ("OMP") and Oasis Midstream Services LLC ("OMS"). OMP is a growth-oriented, fee-based master limited partnership that develops and operates a diversified portfolio of midstream assets. We own a substantial majority of the general partner and a majority of the outstanding units of OMP. As of December 31, 2019, we operated a well services business segment through Oasis Well Services LLC ("OWS"). In March 2020, we intend to transition our well fracturing services from OWS to a third-party provider who will provide services to us under a long-term agreement. We believe this will result in continued quality service, while allowing us to focus on our core operations.

As of December 31, 2019, we have accumulated 408,117 net leasehold acres in the Williston Basin, of which approximately 97% is held by production, and 24,995 net leasehold acres in the Delaware Basin, of which approximately 71% is held by production. In the Williston Basin, we are currently exploiting significant resource potential from the Bakken and Three Forks formations, which are present across a substantial portion of our acreage. In the Delaware Basin, our development activities are focused on the Bone Springs and Wolfcamp formations, and we continue to increase our footprint to drive operational efficiencies. We believe the locations, size and concentration of our acreage in the Williston and Delaware Basins create an opportunity for us to achieve cost, recovery and production efficiencies through the development of our project inventory. 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 2019, we completed and placed on production 78 gross operated wells and had average daily production of 88,061 barrels of oil equivalent per day ("Boepd") in the Williston and Delaware Basins. As of December 31, 2019, we had 1,114 gross (820.9 net) operated producing horizontal wells in the Bakken and Three Forks formations in the Williston Basin and 42 gross (39.5 net) operated producing horizontal wells in the Delaware Basin. As of December 31, 2019, DeGolyer and MacNaughton, our independent reserve engineers, estimated our net proved reserves to be 242.8 million barrels of oil equivalent ("MMBoe") in the Williston Basin, of which 62% were classified as proved developed and 69% were crude oil, and net proved reserves to be 43.6 MMBoe in the Delaware Basin, of which 32% were classified as proved developed and 79% were crude 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 achieve moderate production growth and attractive returns on invested capital in order to maximize the value of our resource potential, while generating free cash flow. During 2019, we completed and brought on production 67 gross (41.6 net) operated wells in the Williston Basin and 11 gross (9.9 net) operated wells in the Delaware Basin. Our 2020 capital plan contemplates completing and placing on production approximately 45 to 55 gross operated wells in the Williston Basin and approximately 20 to 25 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 2020 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. The magnitude and concentration of our acreage within the Williston and Delaware Basins, particularly in the core of the plays, 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 crude oil, natural gas and water fluid handling facilities and infrastructure, and reduce the time and cost of rig mobilization. In addition, we expect our midstream business to continue to provide operational synergies.

- ***Adopt and employ leading drilling and completion techniques.*** Our team is focused on enhancing our drilling and completion techniques to optimize overall project economics. We continuously evaluate our internal drilling and completion results and monitor the results of other operators to improve our operating practices. We continue to optimize our completion designs based on geology and well spacing.
- ***Maintain financial flexibility.*** We are focused on generating free cash flow and reducing debt. We have no short-term debt maturities, and as of December 31, 2019, we had $882.7 million of liquidity available, including $20.0 million of cash and cash equivalents and $862.7 million in the aggregate of unused borrowing 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 expected 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 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. In 2019, we continued to increase our footprint in the Delaware Basin to drive operational efficiencies by acquiring an additional 1,800 highly complementary net acres. Going forward, we may acquire additional acreage in the Williston Basin and the 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.

We also want to produce crude oil and natural gas in a responsible manner while meeting the expectations of a carbon-constrained world, so we continue to focus on environmental, social and governance initiatives by identifying opportunities to minimize our environmental impact, improve safety, invest in our employees and support the communities in which we live and work. We are a recognized industry leader in the capture of the natural gas that we produce due to the proactive and significant investments we have made in our midstream business. As of December 31, 2019, we were capturing approximately 94% of our natural gas production in North Dakota, and our gas capture rate is over 10% higher than the overall average for North Dakota operators. We also provide leadership training and educational and professional development programs for employees at every level of the organization. Additionally, we conduct regular shareholder outreach campaigns focused on compensation practices and other governance topics; and our recently announced updates to our executive compensation program demonstrate our desire to maintain alignment of executive and shareholder interests. For more information about our corporate responsibility efforts, please see the "Sustainability" page of our website and the Proxy Statement that we will file for our 2020 Annual Meeting of Shareholders.

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 crude 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, 2019, we had 408,117 net leasehold acres in the Williston Basin, of which 397,416 net acres were held by production, and 69% of our 242.8 MMBoe estimated net proved reserves in this area were comprised of crude oil. In 2018, we made our initial entry into the Delaware Basin, one of the most prolific crude oil plays in North America, and we continue to build that position. As of December 31, 2019, we had 24,995 net leasehold acres in the Delaware Basin, of which 17,790 net acres were held by production, and 79% of our 43.6 MMBoe estimated net proved reserves in this area were comprised of crude oil. In 2020, we will continue our drilling and completion activities in both the Williston and Delaware Basins.
- ***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. We plan to complete approximately 45 to 55 gross operated wells with a working interest of approximately 66% in the Williston Basin and approximately 20 to 25 gross operated wells with a working interest of approximately 88% in the Delaware Basin in 2020.
- ***Management team with proven operating and acquisition skills.*** Our senior management team has extensive expertise in the crude oil and natural 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 2019, an average of 75% of our executive officers' overall compensation was in long-term equity-based incentive awards, and such officers owned approximately 4.8 million shares of our

outstanding common stock as of December 31, 2019. 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. We have also implemented a number of changes to our 2020 compensation program to further increase our management team's alignment with our shareholders and our strategic objectives.

- ***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, 2019, 96% of our estimated net proved reserves were attributable to properties that we expect to operate. Approximately 95% and 92% of our drilling and completion capital expenditures related to operated wells in 2019 and in our 2020 plan, respectively. Controlling operations enables us to determine the pace of development and better manage the costs, type and timing of exploration and development activities. We believe that maintaining operational control over the majority of our acreage allows us to better pursue our strategies of enhancing returns through operational and cost efficiencies and capital efficiency. We are also better able to manage infrastructure investment to drive down operating costs and optimize crude oil, natural gas and NGL price realizations.
- ***Vertical integration.*** Our investment in and operational control of our midstream business provides 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 and increase transparency in the planning process.

Our operations - exploration and production activities

Proved reserves

Our estimated net proved reserves and related PV-10 at December 31, 2019, 2018 and 2017 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, 2019, 2018 and 2017 in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in crude 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 crude 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 $55.85 per Bbl for crude oil and $2.62 per MMBtu for natural gas, $65.66 per Bbl for crude oil and $3.16 per MMBtu for natural gas and $51.34 per Bbl for crude oil and $2.99 per MMBtu for natural gas for the years ended December 31, 2019, 2018 and 2017, 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 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 crude 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.

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

	At December 31, 2019	2018	2017
Estimated proved reserves:			
Crude oil (MMBbls)	200.8	228.4	225.0
Natural gas (Bcf)	513.5	552.7	523.5
Total estimated proved reserves (MMBoe)	286.4	320.5	312.2
Percent crude oil	70 %	71 %	72 %
Estimated proved developed reserves:			
Crude oil (MMBbls)	113.4	144.5	150.6
Natural gas (Bcf)	314.0	339.4	301.1
Total estimated proved developed reserves (MMBoe)	165.8	201.1	200.8
Percent proved developed	58 %	63 %	64 %
Estimated proved undeveloped reserves:			
Crude oil (MMBbls)	87.4	83.9	74.3
Natural gas (Bcf)	199.5	213.3	222.4
Total estimated proved undeveloped reserves (MMBoe)	120.6	119.4	111.4
Future net revenues (in millions)	$ 5,385.4	$ 8,341.6	$ 6,185.4
Standardized Measure (in millions)[(1)]	$ 2,844.4	$ 4,050.3	$ 3,300.7
PV-10 (in millions)[(2)]	$ 2,934.4	$ 4,674.3	$ 3,683.7

(1) Standardized Measure represents the present value of estimated future net cash flows from proved crude 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 crude oil and natural 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 crude oil and natural gas reserves by basin as of December 31, 2019:

	Proved Developed			Proved Undeveloped		
	Crude oil (MMBbls)	Natural gas (Bcf)	Total (MMBoe)	Crude oil (MMBbls)	Natural gas (Bcf)	Total (MMBoe)
Williston Basin	102.4	295.5	151.7	64.0	162.5	91.1
Delaware Basin	11.0	18.5	14.1	23.3	37.0	29.5
Total	113.4	314.0	165.8	87.3	199.5	120.6

Estimated net proved reserves at December 31, 2019 were 286.4 MMBoe, an 11% decrease from estimated net proved reserves of 320.5 MMBoe at December 31, 2018, primarily due to decreases of 63.3 MMBoe for net negative revisions, 32.1 MMBoe for production and 2.5 MMBoe for divestitures of non-strategic assets in the Williston Basin, partially offset by an increase of 63.9 MMBoe for additions. The net negative revisions were attributable to negative revisions of 51.2 MMBoe due to well performance, 11.2 MMBoe due to lower realized prices and 7.6 MMBoe associated with alignment to the five-year development plan, offset by positive revisions of 6.7 MMBoe due to lower operating expenses.

Our proved developed reserves decreased 35.3 MMBoe, or 18%, to 165.8 MMBoe for the year ended December 31, 2019 from 201.1 MMBoe for the year ended December 31, 2018, primarily due to decreases of 37.5 MMBoe for net negative revisions, 32.1 MMBoe for production and 1.5 MMBoe for divestitures. These decreases were partially offset by our 2019 development program, which included 130 gross (52.1 net) wells that were completed and brought on production during 2019 and resulted in conversions of proved undeveloped reserves ("PUDs") of 25.5 MMBoe and additions of 10.3 MMBoe. Proved developed revisions were primarily due to negative revisions of 30.2 MMBoe for performance largely related to higher than anticipated decline rates in recently developed spacing units and 9.6 MMBoe due to lower realized prices, partially offset by positive revisions of 5.1 MMBoe due to lower operating expenses.

Our proved undeveloped reserves increased 1.2 MMBoe, or 1%, to 120.6 MMBoe for the year ended December 31, 2019 from 119.4 MMBoe for the year ended December 31, 2018 primarily due to additions of 53.6 MMBoe, offset by net negative revisions of 25.9 MMBoe, the conversion of wells to proved developed of 25.5 MMBoe and divestitures of 1.0 MMBoe. The proved undeveloped revisions were primarily due to negative revisions of 21.1 MMBoe for performance largely related to reductions in the anticipated hydrocarbon recoveries of proved areas during full field development due to changes in anticipated well densities and well performance and 7.0 MMBoe associated with alignment to the anticipated five-year development plan, offset by positive revisions of 1.7 MMBoe due to lower operating expenses.

See Note 26 to our consolidated financial statements for more information on our proved reserves for the years ended December 31, 2018 and 2017. For the comparison of the years ended December 31, 2018 and 2017, refer to "Item 1. Business—Our operations - exploration and production activities" in our Annual Report on Form 10-K for the year ended December 31, 2018, filed with the SEC on March 1, 2019.

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 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 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 crude 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,		
	2019	2018	2017
		(In millions)	
Standardized Measure of discounted future net cash flows	$ 2,844.4	$ 4,050.3	$ 3,300.7
Add: present value of future income taxes discounted at 10%	90.0	624.0	383.0
PV-10	$ 2,934.4	$ 4,674.3	$ 3,683.7

The PV-10 of our estimated net proved reserves at December 31, 2019 was $2,934.4 million, a 37% decrease from PV-10 of $4,674.3 million at December 31, 2018. This decrease was primarily due to lower commodity price assumptions and a decrease in reserves year over year.

Proved undeveloped reserves

At December 31, 2019, we had approximately 120.6 MMBoe of proved undeveloped reserves as compared to 119.4 MMBoe at December 31, 2018. The following table summarizes the changes in our proved undeveloped reserves during 2019:

	Year Ended December 31, 2019
	(MBoe)
Proved undeveloped reserves, beginning of period	119,430
Extensions, discoveries and other additions	53,578
Sales of minerals in place	(1,008)
Revisions of previous estimates	(25,859)
Conversion to proved developed reserves	(25,516)
Proved undeveloped reserves, end of period	120,625

During 2019, we spent a total of $275.0 million related to the development of proved undeveloped reserves, $62.7 million of which was spent on proved undeveloped reserves that represent wells in progress at year-end. The remaining $212.3 million resulted in the conversion of 25.5 MMBoe of proved undeveloped reserves, or 21% of our proved undeveloped reserves balance at the beginning of 2019, to proved developed reserves. We added 53.6 MMBoe of proved undeveloped reserves as a result of our five-year development plan. The 2019 proved undeveloped revisions of 25.9 MMBoe were primarily due to negative revisions of 21.1 MMBoe for performance largely related to reductions in the anticipated hydrocarbon recoveries of proved areas during full field development due to changes in anticipated well densities and well performance and 7.0 MMBoe associated with alignment to the anticipated five-year development plan, offset by positive revisions of 1.7 MMBoe due to lower operating expenses.

We expect to develop all of our proved undeveloped reserves, including all wells drilled but not yet completed, as of December 31, 2019 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, the Oasis Credit Facility (as defined in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources") 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 11% of our proved undeveloped reserves at December 31, 2019 are attributable to wells that have been drilled but not yet completed, and 77% and 23% of our undrilled reserves are within our core acreage in the Williston Basin and the Delaware Basin, respectively.

Independent petroleum engineers

Our estimated net proved reserves and related future net revenues and PV-10 at December 31, 2019, 2018 and 2017 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 crude oil and natural 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 crude oil, natural 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.

Technology used to establish proved reserves

In accordance with rules and regulations of the SEC applicable to companies involved in crude oil and natural gas producing activities, proved reserves are those quantities of crude 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 crude 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 and Chief Engineer, is the technical person primarily responsible for overseeing our reserves evaluation process. He has over 30 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 and Chief Engineer;
- 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 crude oil, natural gas and NGLs, which are commodities. The price that we receive for the crude 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 crude oil or natural gas can result in substantial price volatility. Crude oil supply in the United States has grown dramatically over the past several years, putting downward pressure on crude oil prices. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in crude 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 crude 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 crude oil and natural gas industry and our business—A substantial or extended decline in commodity prices, in crude oil and, to a lesser extent, natural gas and NGL 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 crude oil and natural gas production by basin, realized prices and production costs for the periods presented. 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, 2019	2018	2017
Net production volumes:			
Williston Basin			
Crude oil (MBbls)	20,722	21,786	18,818
Natural gas (MMcf)	52,813	40,550	31,946
Oil equivalents (MBoe)	29,524	28,544	24,143
Average daily production (Boe per day)	80,889	78,203	66,144
Delaware Basin			
Crude oil (MBbls)	2,102	1,264	—
Natural gas (MMcf)	3,093	1,880	—
Oil equivalents (MBoe)	2,618	1,578	—
Average daily production (Boe per day)	7,172	4,322	—
Average sales prices:			
Crude oil, without derivative settlements (per Bbl)	$ 55.27	$ 61.84	$ 48.51
Crude oil, with derivative settlements (per Bbl)(1)	55.89	52.65	47.99
Natural gas, without derivative settlements (per Mcf)(2)	2.64	3.88	3.81
Natural gas, with derivative settlements (per Mcf)(1)(2)	2.72	3.84	3.86
Costs and expenses (per Boe of production):			
Lease operating expenses	$ 6.95	$ 6.44	$ 7.34
Marketing, transportation and gathering expenses	4.01	3.56	2.31
Production taxes	3.50	4.44	3.65
E&P general and administrative expenses (“G&A”)	3.69	3.40	3.21
E&P Cash G&A(3)	2.07	2.48	2.16

(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 NGLs.

(3) E&P Cash G&A, a non-GAAP financial measure, represents G&A expenses less non-cash equity-based compensation expenses and other non-cash charges included in our E&P 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 E&P segment G&A expenses to E&P Cash G&A.

Net production in the Williston Basin for the year ended December 31, 2019 was 29,524 MBoe as compared to net production of 28,544 MBoe for the year ended December 31, 2018. Net production in the Delaware Basin for the year ended December 31, 2019 was 2,618 MBoe as compared to net production of 1,578 MBoe for the year ended December 31, 2018. Our net production in both the Williston and Delaware Basins increased year over year, primarily due to increases in natural gas production, coupled with 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, 2018. Average crude oil sales prices, without derivative settlements, decreased by $6.57 per barrel, or 11%, to an average of $55.27 per barrel for the year ended December 31, 2019 as compared to the year ended December 31, 2018. Giving effect to our derivative transactions in both periods, our crude oil sales prices increased $3.24 per barrel to $55.89 per barrel for the year ended December 31, 2019 from $52.65 per barrel for the year ended December 31, 2018.

For the comparison of the years ended December 31, 2018 and 2017, refer to “Item 1. Business—Our operations - exploration and production activities” in our Annual Report on Form 10-K for the year ended December 31, 2018, filed with the SEC on March 1, 2019.

Productive wells

The following table presents the total and operated gross and net productive wells by basin as of December 31, 2019:

	Total wells		Operated wells	
	Gross	Net	Gross	Net
Williston Basin - horizontal wells	1,486	864.6	1,114	820.9
Williston Basin - other	1	1.0	1	1.0
Delaware Basin - horizontal wells	137	40.1	42	39.5
Delaware Basin - other	34	20.7	20	17.2
Total wells	1,658	926.4	1,177	878.6

All of our productive wells are crude 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, 2019. 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	466,509	355,164	86,469	52,953	552,978	408,117
Delaware Basin	27,356	16,182	13,338	8,813	40,694	24,995
Total	493,865	371,346	99,807	61,766	593,672	433,112

Our total acreage that is held by production decreased to 415,206 net acres at December 31, 2019 from 416,478 net acres at December 31, 2018.

Undeveloped acreage

The following table sets forth the number of gross and net undeveloped acres by basin as of December 31, 2019 that will expire over the next three years unless production is established on the acreage prior to the expiration dates:

	Year ending December 31,					
	2020		2021		2022	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin	10,180	7,420	2,430	2,179	3,319	790
Delaware Basin	3,602	1,389	1,456	357	110	7
Total	13,782	8,809	3,886	2,536	3,429	797

Drilling and completion activity

The following table summarizes our completion activity for the years ended December 31, 2019, 2018 and 2017. 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,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	123	46.2	135	84.2	153	63.0
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total development wells	123	46.2	135	84.2	153	63.0
Exploratory wells:						
Oil	7	5.9	2	1.3	—	—
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	7	5.9	2	1.3	—	—
Total wells	130	52.1	137	85.5	153	63.0

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 participated in 130 gross (52.1 net) wells that were completed and brought on production during the year ended December 31, 2019.

We did not drill any dry hole wells in 2019, 2018 or 2017.

As of December 31, 2019, we had 84 gross (46.1 net) wells in the process of being drilled or completed in the Williston and Delaware Basins, which includes 3 gross operated wells drilling, 54 gross operated wells waiting on completion and 27 gross non-operated wells drilling or completing.

As of December 31, 2019, we had three operated rigs running and expect to run four operated rigs, two in both the Williston and Delaware Basins, while concentrating drilling activities within our top-tier acreage in 2020.

Capital expenditures

In 2019, we spent $631.0 million on capital expenditures, excluding midstream capital expenditures, which represented a 67% decrease as compared to the $1,925.8 million spent on capital expenditures, excluding midstream capital expenditures, during 2018. Excluding acquisitions of $21.0 million in 2019 and $951.9 million in 2018, which includes the Permian Basin Acquisition (as defined in Item 1. Business—Our operations - exploration and production activities —Description of properties—Delaware Basin), our non-midstream capital expenditures decreased to $610.0 million in 2019 from $974.0 million spent during 2018, which represented a 37% decrease year over year. This decrease was attributable to decreased drilling and completion activity as a result of lower commodity prices in 2019. 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."

We have decreased our planned 2020 capital expenditures as compared to 2019, excluding acquisitions and midstream, as a result of current commodity prices. Our total 2020 capital expenditure plan, excluding midstream capital expenditures, is approximately $575 million to $595 million, which includes approximately $316 million to $387 million focused in the Williston Basin and approximately $201 million to $268 million focused in the Delaware Basin (with approximately 80-90% of the E&P capital allocated to drilling and completions). In addition, our 2020 planned capital expenditures includes other capital expenditures for administrative capital and excludes capitalized interest of approximately $12.5 million. We plan to complete and place on production approximately 45 to 55 gross operated wells in the Williston Basin and approximately 20 to 25 gross operated wells in the Delaware Basin in 2020.

While we have planned approximately $575 million to $595 million in 2020 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

Williston Basin

As of December 31, 2019, 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, 2019, our total leasehold position in the Williston Basin consisted of 408,117 net acres, and we had a total of 865.6 net producing wells and 821.9 net operated producing wells in the Williston Basin. We had average daily production of 80,889 net Boe per day for the year ended December 31, 2019 in the Williston Basin. During 2019, our Bakken and Three Forks wells produced a daily average of 80,876 net Boe per day with 820.9 net operated producing wells on December 31, 2019. Accordingly, our 820.9 net operated producing Bakken and Three Forks wells were responsible for nearly 100% of our average daily production during 2019. As of December 31, 2019, our working interest for all producing Bakken and Three Forks wells averaged 58% and averaged 74% in the wells we operate.

Delaware Basin

In February 2018, we closed on an acquisition of approximately 22,000 net acres in the Delaware Basin (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. In 2019, we continued to increase our footprint in the Delaware Basin to drive operational efficiencies by acquiring an additional 1,800 highly complementary net acres.

As of December 31, 2019, our total leasehold position in the Delaware Basin consisted of 24,995 net acres, and we had a total of 60.8 net producing wells and 56.7 net operated producing wells in the Delaware Basin. We had average daily production of 7,172 net Boe per day for the year ended December 31, 2019 in the Delaware Basin. During 2019, our horizontal wells in the Delaware Basin produced a daily average of 6,915 net Boe per day with 39.5 net operated producing wells on December 31, 2019. Accordingly, our 39.5 net operated producing horizontal wells in the Delaware Basin were responsible for nearly 96% of our average daily production during 2019. As of December 31, 2019, our working interest for all producing horizontal wells in the Delaware Basin averaged 29% and in the wells we operate averaged 94%.

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 2019, crude oil production in North Dakota was approximately 1,476,000 barrels per day. According to the North Dakota Pipeline Authority website's data last updated February 14, 2020, there was approximately 1,381,000 barrels per day of combined crude oil pipeline transportation and refining capacity and approximately 1,305,000 barrels per day of specifically dedicated rail loading capacity in the Williston Basin as of December 31, 2019. In 2019, 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, 2019, we were flowing approximately 93% of our gross operated crude oil production through these gathering systems in the Williston Basin. In the Delaware Basin, approximately 70% of our gross operated crude oil production was connected to crude oil gathering systems as of December 31, 2019.

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 ("NYMEX 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 crude 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 crude oil transportation out of the Williston Basin and improved basin differentials received at the lease. In the fourth quarter of 2019, as production increased and existing pipelines in the Williston Basin were running again at peak rates, rail transportation increased and the differentials widened to more than $3.50 per barrel below NYMEX WTI. However, additional transportation capacity is expected to come on-line beginning in mid-2020, and we expect the differential to compress again to mid-2019 levels. In the Delaware Basin, price differentials in the first half of 2019 averaged more than $5.00 per barrel below NYMEX WTI due to pipeline constraints. Expansions of pipelines began to occur in mid-2019 which greatly reduced these differentials, which became positive to NYMEX WTI by year-end. 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 crude oil and natural gas industry and our business—Insufficient transportation, end-market refining utilization or natural gas processing capacity in the Williston Basin and the Delaware Basin could cause significant fluctuations in our realized crude oil and natural gas prices.”

We principally sell our crude oil, natural gas and NGL production to refiners, marketers and other purchasers that have access to nearby pipeline and rail facilities. Our marketing of crude 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 crude oil and natural gas industry and our business—Market conditions or operational impediments may hinder our access to crude oil, natural gas and NGLs markets or delay our production” and “Item 1A. Risk Factors—Risks related to the crude oil and natural gas industry and our business—Insufficient transportation, end-market refining utilization or natural gas processing capacity in the Williston Basin and the Delaware Basin could cause significant fluctuations in our realized crude oil and natural gas prices.”

In an effort to improve price realizations from the sale of our crude oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our crude oil and natural gas to a broad array of potential purchasers. As of December 31, 2019, we sold a substantial majority of our crude 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 crude 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 crude 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, 2019, sales to Phillips 66 Company accounted for approximately 14% of our total sales from the exploration and production segment. For the year ended December 31, 2018, no purchaser accounted for more than 10% of the Company’s total sales from the exploration and production segment. For the year ended December 31, 2017, sales to Shell Trading (US) Company accounted for approximately 16% of our total sales from the exploration and production segment. No other purchasers accounted for more than 10% of our total sales from the exploration and production segment for the years ended December 31, 2019 and 2017. 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 crude oil, natural gas and NGL 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 crude oil and natural gas. The price we receive for our crude 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 crude oil supply, foreign imports, political conditions in other crude 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 crude oil and natural gas industry and our business—A substantial or extended decline in commodity prices, in crude oil and, to a lesser extent, natural gas and NGL 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 crude 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 crude oil and natural gas industry and our business—If crude oil, natural gas and NGL 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 gas properties.”

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

Our operations - midstream services

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

Our midstream 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, 2019, our ownership interest in OMP consisted of a 67.5% limited partner interest and 91% 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 four development companies (collectively, the "DevCos"): Bighorn DevCo LLC ("Bighorn DevCo"), Bobcat DevCo LLC ("Bobcat DevCo"), Beartooth DevCo LLC ("Beartooth DevCo") and Panther DevCo LLC ("Panther DevCo").

In the Williston Basin, 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 acreage to OMP in which OMP has the right to provide crude oil, natural gas and water services to support our existing and future volumes. Outside of Wild Basin, we have dedicated acreage to OMP for produced and flowback water services and freshwater services. OMP expanded its operations to the Delaware Basin in the fourth quarter of 2019 when, effective November 1, 2019, we agreed to assign to Panther DevCo certain crude oil gathering and produced and flowback water gathering and disposal assets (the "Delaware Midstream Assets"), which were already under development by OMS, to support our production in the Delaware Basin. Also on November 1, 2019, Panther DevCo entered into long-term commercial agreements with us, pursuant to which we dedicated acreage in the Delaware Basin to OMP for crude oil gathering and produced and flowback water gathering and disposal services. In addition, OMP has received certain commitments from third parties in the Williston Basin and the Delaware Basin, in which OMP has the right to provide its full suite of midstream services to support existing and future third party volumes.

Contractual arrangements

We have entered into several long-term, fee-based contractual arrangements with OMP for midstream services, including (i) natural gas gathering, compression, processing and gas lift services; (ii) crude oil 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") as of December 31, 2018.

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. After the OMP Dropdown, we owned 75% of the non-controlling interests of Bobcat DevCo and 30% of the non-controlling interests of Beartooth DevCo as of December 31, 2018.

2019 Capital Expenditures Arrangement

On February 22, 2019, we entered into a memorandum of understanding (the "MOU") with OMP regarding the funding of Bobcat DevCo's expansion capital expenditures for the 2019 calendar year (the "2019 Capital Expenditures Arrangement"). Pursuant to the MOU, in exchange for increasing its percentage ownership interest in Bobcat DevCo, OMP agreed to make up to $80.0 million of the capital contributions to Bobcat DevCo that OMS would otherwise have been required to contribute. During the year ended December 31, 2019, OMP made capital contributions to Bobcat DevCo pursuant to the 2019 Capital Expenditures Arrangement of $73.0 million. As a result, OMS's ownership interest in Bobcat DevCo decreased from 75% as of December 31, 2018 to 64.7% as of December 31, 2019. The 2019 Capital Expenditures Arrangement ended on December 31, 2019.

Capital expenditures

In 2019, midstream capital expenditures were primarily related to the growth of natural gas gathering and compression to connect Oasis and third party wells to the Wild Basin gas processing complex. Additional capital was spent on the gas processing complex as well as crude oil gathering and produced water gathering and disposal for Oasis and third party customers. Total midstream capital expenditures have decreased year over year, and our planned 2020 midstream capital expenditures are expected to approximate $110 million to $120 million, which includes $68 million to $75 million attributable to OMP.

Competition

The crude oil and natural gas industry is worldwide and highly competitive in all phases. We encounter competition from other crude oil and natural gas companies in all areas of operation, including the acquisition of leasing options on oil and gas properties to the exploration and development of those properties. Our competitors include major integrated crude oil and natural gas companies, numerous independent crude 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 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 crude oil and natural gas industry and our business—Competition in the crude oil and natural gas industry is intense, making it more difficult for us to acquire properties, market crude oil and natural gas and secure trained personnel."

Title to properties

As is customary in the crude 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 crude 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 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 crude 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 crude 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 crude oil and natural gas industry

Our crude 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, crude oil and natural gas production, crude 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 crude oil and natural gas production or otherwise provide midstream services have statutory provisions regulating the exploration for and production of crude 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 crude 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 crude 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 crude oil

Sales of crude oil, condensate and NGLs 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 crude oil by common carrier pipelines is also subject to rate and access regulation. FERC regulates interstate crude oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate crude 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 crude 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 crude oil index to change transportation rates annually every July 1, and our Bighorn DevCo Johnson's Corner line will utilize the FERC crude 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 crude 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 crude 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 crude 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 crude oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate crude oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude 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 crude 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 crude 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 crude 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 crude 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. Due to several crude oil train derailments in the past decade, transportation safety regulators in the United States and Canada have examined the adequacy of transporting crude oil by rail, with an emphasis on the safe transport of Bakken crude oil by rail, following findings by the U.S. Pipeline and Hazardous Materials Safety Administration ("PHMSA") that Bakken crude oil tends to be more volatile and flammable than certain other crude oils, and thus poses an increased risk for a significant accident.

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 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, new operational protocols for trains transporting large volumes of flammable liquids 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. 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, and more recently in February 2019, PHMSA published a final rule requiring railroads to develop and submit comprehensive oil spill response plans for specific route segments traveled by 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. Additionally, the February 2019 final rule requires railroads to establish geographic response zones along various rail routes, ensure that both personnel and equipment are staged and prepared to respond in the event of an accident, and share information about high-hazard flammable train operations with state and tribal emergency response commissions.

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, urge the federal government to strengthen requirements for these operations or otherwise seek to impose more stringent standards on rail transport of crude oil. For example, in the absence of a current federal standard on the vapor pressure of crude oil transported by rail, the State of Washington passed a law that became effective on July 28, 2019, prohibiting the loading or unloading of crude oil from a rail car in the state unless the crude oil vapor pressure is lower than 9 pounds per square inch. In response, the States of North Dakota and Montana filed a preemption application with PHMSA in July 2019, in which the states seek to have PHMSA make an administrative determination and override the Washington State vapor pressure limits. In July 2019, PHMSA published an invitation for public comments on the preemption application, which comment period closed in the latter half of 2019, with no administrative determination yet being released.

Safety improvements or updates to existing tank cars, together with more stringent requirements relating to response planning, equipment and personnel staging preparedness, and establishment of geographic response zones that are imposed under PHMSA's final rules 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 rules or that restrictions on rail transport of crude oil due to state crude oil volatility standards, if not preempted by PHSMA, 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 crude 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 during 2018 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 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 crude oil, natural gas and NGLs 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, Montana and Texas, which have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum allowable rates of production from crude 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 crude 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, all three states impose a production or severance tax with respect to the production and sale of crude oil, natural gas and NGLs within their jurisdictions.

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

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 $1,291,894 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 $1,291,894 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 $1,231,690 per day per violation, adjusted annually for inflation, in addition to any applicable penalty under the Federal Trade Commission Act.

Texas Railroad Commission crude oil and natural gas rules

The Texas Railroad Commission (the "RRC"), through its Oil and Gas Division, regulates the exploration, production and transportation of crude oil and natural gas in Texas. Among other duties, the RRC develops and adopts regulations to prevent waste of the state's crude 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, density and special field rules. Additionally, each month, the RRC assigns production allowables on crude 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 crude oil leases and gas wells and audits the crude oil disposition path to ensure production did not exceed allowables. The RRC also regulates crude 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 productive or 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. Moreover, flaring of natural gas is subject to regulation by the RRC under its rules, but those rules allow for permitted exceptions through the use of flare permits. Flaring may provide crude oil and natural gas producers with an approved means for continuing crude oil production under certain scenarios, such as, for example, when there may be insufficient pipeline infrastructure in place to transport natural gas to market or to prevent resource waste. The imposition of more stringent requirements by the RRC or as a result of litigation contesting such flare permit practice that lessen producers' opportunities to flare under RRC permitted exceptions could result in reduced production, which development could have an adverse effect on our and similarly situated producers' business and results of operations.

North Dakota Industrial Commission crude oil and natural gas rules

The North Dakota Industrial Commission (the "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. On April 1, 2020, new oil and gas rules are expected to be issued by the NDIC that focus primarily on permitting requirements for treating plants, saltwater handling facilities and underground injection control procedures. These requirements have increased or will increase the well costs incurred by us and similarly situated crude 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 crude 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 and the program. 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 crude 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 hazardous liquid and gas pipeline facilities. These laws have resulted in the adoption of rules by PHMSA, that, among other things, require transportation pipeline operators to develop and implement integrity management programs to comprehensively evaluate certain relatively higher risk areas, known as high consequence areas (“HCA”) and moderate consequence areas (“MCA”) along pipelines and take additional safety measures to protect people and property in these areas. The HCAs for natural gas pipelines are predicated on high-population areas (which, for natural gas transmission pipelines, may include Class 3 and Class 4 areas) whereas HCAs for crude oil, NGL and condensate pipelines are based on high-population areas, certain drinking water sources and unusually sensitive ecological areas. An MCA is attributable to natural gas pipelines and is based on high-population areas as well as certain principal, high-capacity roadways, though it does not meet the definition of a natural gas pipeline HCA. 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.

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 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 September 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 gas pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued an interim rule in 2016 and a final rule on October 1, 2019 to implement the agency’s expanded authority to address such conditions or practices that pose an imminent hazard to life, property or the environment. Because the 2016 Pipeline Safety Act reauthorized PHMSA’s hazardous liquid and gas pipeline programs only through September 30, 2019, we anticipate that Congress will issue an updated pipeline safety law in 2020 that will reauthorize those programs through 2023.

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, on October 1, 2019, PHMSA published a final rule for hazardous liquid transmission and gathering pipelines that becomes effective July 1, 2020 and significantly extends and expands the reach of certain PHMSA hazardous liquid integrity management requirements, regardless of the pipeline’s proximity to a HCA (for example, integrity assessments at least once every 10 years of onshore, piggable, hazardous liquid pipeline segments located outside of HCAs, and expanded use of leak detection systems beyond HCAs to all regulated hazardous liquid pipelines other than offshore gathering and regulated rural gathering pipelines). The final rule also requires all hazardous liquid pipelines in or affecting a HCA to be capable of accommodating in line inspection tools within the next 20 years unless the basic construction of a pipeline cannot be modified to permit that accommodation. Also, this final rule extends annual, accident, and safety-related conditional reporting requirements to hazardous liquid gravity lines and certain gathering lines and also imposes inspection requirements on hazardous liquid pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes or other similar events that are likely to damage infrastructure. In a second example, in 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain gas lines and gathering lines including, among other things, expanding certain of PHMSA’s current regulatory safety programs for gas pipelines in newly defined MCAs that contain as few as five dwellings within a potential impact area; requiring 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 gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. PHMSA has since decided to split its 2016 proposed rule, which has become known as the “gas mega rule,” into three separate rulemaking proceedings to facilitate completion. The first of these three rulemakings, relating to onshore gas transmission pipelines, was published as a final rule on October 1, 2019, becomes effective on July 1, 2020, and imposes numerous requirements on such pipelines, including MAOP reconfirmation, the assessment of additional pipeline mileage outside of HCAs (including all MCAs and those Class 3 and Class 4 areas found not to be in HCAs) within 14 years of publication date and at least once every 10 years thereafter, the reporting of exceedances of MAOP, and the consideration of seismicity as a risk factor in integrity management. The remaining rulemakings comprising the gas mega rule are expected to be issued in 2020. 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, crude 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 crude oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the crude 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 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 crude 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 crude 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, in response to a federal consent decree issued in 2016, the EPA was required during 2019 to determine whether certain Subtitle D criteria regulations required revision in a manner that could result in oil and natural gas wastes being regulated as RCRA hazardous wastes. In April 2019, the EPA made a determination that such revision of the regulations was unnecessary. 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 crude 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 or expansion of crude 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. Since that time, the EPA has issued area designations with respect to ground-level ozone and has 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 crude 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 crude 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 crude oil per day if at least 60% of the monthly volume of associated natural gas produced from the well is captured, or otherwise crude 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 who is 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. In late 2019, the overall natural gas capture rate for producers in North Dakota failed to attain the current statewide gas capture rate of 88%, and the gas capture rate will increase to 91% on November 1, 2020. As of December 31, 2019, we were capturing approximately 94% of our natural gas production in North Dakota. While we were satisfying the applicable gas capture percentage goals as of December 31, 2019 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.

Climate change

Climate change continues to attract considerable public, political and scientific attention. As a result, numerous regulatory initiatives 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 existing emissions of greenhouse gases ("GHGs") as well as to restrict or eliminate such future emissions. These regulatory efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. Additionally, the threat of climate change has resulted in increasing political, litigation and financial risks associated with the production of fossil fuels and emission of GHGs. The adoption and implementation of any federal or state legislation, regulations or executive orders or the occurrence of any litigation or financial developments that impose more stringent requirements or bans on GHG-emitting production activities or locations where such production activities may occur, impose liabilities for past conduct relating to GHG-emitting production activities or limit or eliminate sources of financing for on-going production operations could require our E&P customers to incur increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas that, in turn, could reduce demand for our products and services. See "Item 1A. Risk Factors – Our E&P and midstream operations are subject to a number of risks arising out of concerns regarding the threat of climate change that could result in increased operating costs and costs of compliance, limit the areas in which crude oil and natural gas production may occur, and reduce demand for the crude oil and natural gas that we produce or provide midstream services for while the physical effects of climate change could disrupt our production or midstream services and cause us to incur significant costs in preparing for or responding to those effects" for additional information relating to risks arising out of climate change including the emission of GHGs.

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 (the "Corps") under the Obama Administration issued a final rule outlining their position on the federal jurisdictional reach over waters of the United States. In 2017, the EPA and the Corps under the Trump Administration agreed to reconsider the 2015 rule and, thereafter, in October 2019, the agencies published a final rule made effective on December 23, 2019, rescinding the 2015 rule. On January 23, 2020, the two agencies issued a final rule re-defining the Clean Water Act's jurisdiction over waters of the

United States, which redefinition is narrower than found in the 2015 rule. Upon being published in the Federal Register and the passage of 60 days thereafter, the January 23, 2020 final rule will become effective, at which point the United States will be covered under a single regulatory scheme as it relates to federal jurisdictional reach over waters of the United States. However, there remains the expectation that the January 23, 2020 final rule also will be legally challenged in federal district court. To the extent that any challenge to the January 23, 2020 final rule is successful and the 2015 rule or revised rule expands the scope of the Clean Water Act's jurisdiction in areas where we conduct operations, our drilling programs could incur increased costs and delays or cancellations with respect to obtaining permits for dredge and fill activities in wetland areas, which could reduce demand for our production.

The Oil Pollution Act of 1990 (the "OPA") amends the Clean Water Act and sets minimum standards for prevention, containment and cleanup of crude 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 crude oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from crude 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 crude 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 (the "SDWA") Underground Injection Control (the "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 seismic events near underground injection wells used for the disposal of produced water from crude 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 six states with areas of increased rates of induced seismicity that could be attributed to fluid injection or crude oil and natural gas extraction. Since that time, the United States Geological Survey indicates that these rates have decreased in these states, although concern continues to exist over quakes arising from induced seismic activities. 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 RRC 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 crude oil and natural 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.

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 crude oil and natural gas commissions or similar agencies, but 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 advance notice of proposed rulemaking ("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 crude oil and natural gas hydraulic fracturing or from compressors, controls, dehydrators, storage tanks, natural gas processing plants, and certain other equipment. In addition, the EPA has published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional crude oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The federal Bureau of Land Management (the "BLM") published a final rule in 2015 that established new or more stringent standards for performing hydraulic fracturing on federal and Indian lands but the BLM rescinded the 2015 rule in late 2017; however, litigation challenging the BLM's decision to rescind the 2015 rule is pending in federal district court.

From time to time Congress has considered, but has not adopted, 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. However, the threat of climate change has resulted in increasing political risks in the United States, including climate-related pledges to ban hydraulic fracturing of oil and gas wells being made by certain candidates seeking the office of President of the United States in 2020.

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 adopt certain prohibitions on hydraulic fracturing, following the approach taken by the States of Maryland, New York and Vermont. 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 or bans relating to the hydraulic fracturing process are adopted in areas where we operate, or in the future plan to operate, we could incur potentially significant added costs to comply with such requirements, experience restrictions, delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be limited or precluded from drilling wells or in the volume that the Company is ultimately able to produce from its reserves.

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, crude 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 crude 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 crude 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 (the "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, the U.S. Fish and Wildlife Service may make determinations on the listing of species as endangered or threatened under the ESA and litigation with respect to the listing or non-listing of certain species as endangered or threatened may result in more fulsome protections for non-protected or lesser-protected species pursuant to specific timelines. The designation of unidentified threatened or endangered species or the re-designation of under-protected species 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.

Operations on federal lands

Performance of crude oil and natural gas E&P activities on federal lands, including Indian lands and lands administered by the 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 crude 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, 2019, we employed 609 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, 2019, we leased 130,300 square feet of office space in Houston, Texas at 1001 Fannin Street, where our principal offices are located, and sub-leased 7,800 square feet of office space in Midland, Texas. The lease for our Houston office expires in March 2029 and the sub-lease for our Midland office expires in August 2020. 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.

Since December 24, 2019, our common stock has been listed and traded on The Nasdaq Stock Market LLC ("Nasdaq") under the symbol "OAS." Before December 24, 2019, our common stock was listed and traded on the New York Stock Exchange. We 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.

Other information, such as presentations, the charter of the Audit, Compensation and Nominating and Governance Committees and the Code of Business Conduct and Ethics are available on our website, http://www.oasispetroleum.com, under "Investor Relations — Corporate Governance" and in print to any shareholders who provide a written request to the Corporate Secretary at 1001 Fannin Street, Suite 1500, Houston, Texas 77002.

Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including the Chief Executive Officer and Chief Financial Officer. Within the time period required by the SEC and Nasdaq, as applicable, we will post on our website any modification to the Code of Business Conduct and Ethics and any waivers applicable to senior officers who are defined in the Code of Business Conduct and Ethics, as required by the Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley Act").

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 crude oil and natural gas industry and our business

A substantial or extended decline in commodity prices, in crude oil and, to a lesser extent, natural gas and NGL 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 crude oil and, to a lesser extent, natural gas and NGLs, heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil, natural gas and NGLs are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for crude oil, natural gas and NGL has been volatile. For example, average daily prices for NYMEX WTI crude oil ranged from a high of $66.24 per barrel to a low of $46.31 per barrel during 2019. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $4.25 per MMBtu to a low of $1.75 per MMBtu during 2019. Likewise, NGLs, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics, have experienced significant declines in realized prices since the fall of 2014. 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 crude oil, natural gas and NGLs;
- the actions of OPEC;
- the price and quantity of imports of foreign crude oil, natural gas and NGL;
- political conditions in or affecting other crude oil, natural gas and NGL producing countries, including the current conflicts in the Middle East and conditions in South America, China, India and Russia;
- the level of global crude oil, natural gas and NGL E&P activities;
- the level of global crude oil, natural gas and NGL inventories;
- events that impact global market demand, including impacts from global health epidemics and concerns, such as the coronavirus;
- 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 crude oil and the speculative trading of crude 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 crude oil, natural gas and NGL and related infrastructure;
- price and availability of competitors' supplies of crude oil, natural gas and NGL;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our crude oil and natural gas production is sold to purchasers under short-term (less than twelve-month) contracts at market-based prices, and our NGL production is sold to purchasers under long-term (more than twelve-month) contracts at market-based prices. Low crude oil, natural gas and NGL 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 crude oil and natural gas reserves" below. Low crude oil, natural gas and NGL prices may also reduce the amount of crude oil, natural gas and NGL 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 crude oil and natural gas reserves" below.

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 crude oil, natural gas and NGL 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 crude oil, natural gas and NGL 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 oil and gas assets, including mortgage liens on oil and 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. OMP's obligations under the OMP Credit Facility are collateralized by mortgages and other security interests on substantially all of OMP's and its subsidiaries' properties and assets, including the equity interests in all present and future subsidiaries (subject to certain exceptions). Some or all of the collateral owned by Bobcat DevCo and Beartooth DevCo is subject to an intercreditor agreement between Wells Fargo, National Association ("Wells Fargo"), as administrative agent for the OMP Credit Facility, and Wells Fargo as the administrative agent for the Oasis Credit Facility, and acknowledged by OMS, Bobcat DevCo and Beartooth DevCo. If OMP is unable to repay its indebtedness under the OMP Credit Facility, the lenders could seek to foreclose on OMP's assets. However, there are no cross-default rights between the Revolving Credit Facilities. Therefore, an acceleration of the OMP Credit Facility will not trigger automatically an acceleration of the Oasis Credit Facility. 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, 2019, we had $337.0 million of outstanding borrowings and had $15.1 million of outstanding letters of credit under the Oasis Credit Facility, $458.5 million of outstanding borrowings and had $1.7 million of outstanding letters of credit under the OMP Credit Facility, $862.7 million available for future secured borrowings under the Revolving Credit Facilities and $1,982.6 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, crude oil, natural gas and NGL prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. If crude oil, natural gas and NGL 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, the Oasis Credit Facility borrowing base is subject to periodic redeterminations. We could be forced to repay a portion of our bank borrowings under the Oasis Credit Facility 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 crude oil and natural gas, we currently, and may in the future, enter into derivative arrangements for a portion of our crude 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 crude oil and natural gas and may expose us to cash margin requirements.

Drilling for and producing crude 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 crude 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 crude 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 in 2018 represented our initial expansion outside of the Williston Basin, and we may encounter new obstacles operating in different 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 crude oil, natural gas and NGL 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 crude 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 crude 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 crude oil and natural gas reserves and the PV-10 and Standardized Measure of discounted future net revenues as of December 31, 2019, 2018 and 2017.

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 crude 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 crude oil and natural gas reserves are inherently imprecise.

Actual future production, crude 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 crude 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 crude 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 crude oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2019, 2018 and 2017, 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 gas properties will be affected by factors such as:

- actual prices we receive for crude 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 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 crude 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.

If crude oil, natural gas and NGL 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 gas properties.

We review our proved oil and 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 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 crude oil, natural gas and NGL 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 crude oil prices, we reviewed our proved oil and gas properties for impairment as of December 31, 2019, 2018 and 2017. For the years ended December 31, 2019 and 2017, no impairment was recorded on our proved oil and gas properties. 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 gas properties held for sale to their estimated fair value, determined based on the expected sales price less costs to sell. During the years ended December 31, 2019, 2018 and 2017, we recorded non-cash impairment charges of $5.4 million, $0.9 million and $6.9 million, respectively, on our unproved properties due to expiring leases, periodic assessments and drilling plan uncertainty on certain acreage 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 or Texas 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 crude 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 crude oil, natural gas and NGL 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.

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 crude 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 crude oil and natural gas reserves. Excluding acquisitions of $21.0 million in 2019 and $951.9 million in 2018, we spent $822.4 million and $1,251.6 million related to capital expenditures for the years ended December 31, 2019 and 2018, respectively. Our total capital expenditure plan for 2020 is approximately $685 million to $715 million, which includes approximately $575 million to $595 million for E&P and other capital expenditures, including approximately $316 million to $387 million focused in the Williston Basin and approximately $201 million to $268 million focused in the Delaware Basin (with approximately 80-90% of the E&P capital allocated to drilling and completions). Other capital expenditures includes administrative capital, and excludes capitalized interest of approximately $12.5 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 $1,375.0 million over the next five years to develop the proved undeveloped reserves in the Williston Basin and the Delaware Basin covered by its December 31, 2019 reserve report. Additionally, OMP will continue to invest in midstream assets to support our E&P business segment as well as third-party customers. 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 crude oil, natural gas and NGL we are able to produce from existing wells and new projected wells;
- the prices at which our crude oil, natural gas and NGL are sold;
- the costs of developing and producing our crude 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 crude oil, natural gas or NGL 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.

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 the Delaware Basin regions, making us vulnerable to risks associated with operating among a limited number of geographic areas.

As of December 31, 2019, 92% of our production was located in the Williston Basin in northwestern North Dakota and northeastern Montana and the remaining 8% of our production was 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 the 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 crude 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 crude oil and natural gas producing areas such as the Williston Basin and the 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 in 2018 represented our initial expansion outside of the Williston Basin, and we may encounter new obstacles operating in different geographic regions.

Our operations have historically focused on a single geographic region, namely the North Dakota and Montana regions of the Williston Basin. 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 Williston Basin project areas. As a result, we may encounter obstacles that may cause us not to achieve the expected results of the Permian Basin Acquisition and subsequent bolt-on acquisitions. 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 crude oil and natural gas gathering and transportation facilities, some of which are owned by third parties.

The marketability of our crude oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by midstream operators, including 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, the flaring of natural gas that could result in restrictions on production or monetary sanctions, or the delay, or discontinuance of, development plans for properties. See also “Market conditions or operational impediments may hinder our access to crude oil, natural gas and NGLs markets or delay our production” and “Insufficient transportation, end-market refining utilization or natural gas processing capacity in the Williston Basin and the Delaware Basin could cause significant fluctuations in our realized crude oil and natural gas prices” below. The transportation of our production can be interrupted by other customers that have firm arrangements. In addition, these midstream operators 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 midstream operators 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 midstream operators’ 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 or NGL train derailments or crashes as well as state or federal restrictions on the vapor pressure of crude oil transported by, or loaded on or unloaded from, railcars could also impact our ability to market and deliver our products and cause significant fluctuations in our realized crude 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 the Delaware Basin could cause significant fluctuations in our realized crude oil and natural gas prices.

The crude oil business environment has historically been characterized by periods when crude oil production has surpassed local transportation and refining capacity, resulting in substantial discounts in the price received for crude oil versus prices quoted for NYMEX WTI crude oil. In the past, there have been periods when this discount has substantially increased due to the production of crude 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 crude oil transportation out of the Williston Basin and the Delaware Basin and improved basin differentials 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 the fourth quarter of 2019, as production increased and existing pipelines in the Williston Basin were again running at peak rates, rail transportation increased and our Williston Basin price differentials relative to NYMEX WTI widened to more than $3.50 per barrel below NYMEX WTI. In the first half of 2019, our Delaware Basin price differentials relative to NYMEX WTI weakened due to transportation capacity restraints, averaging more than $5.00 per barrel below NYMEX WTI. However, expansions of pipelines began to occur in mid-2019 which greatly reduced these differentials, which became positive to NYMEX WTI by year-end.

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

Market conditions or the unavailability of satisfactory crude oil and natural gas transportation arrangements may hinder our access to crude oil and natural gas markets or delay our production. The availability of a ready market for our crude oil and natural gas production depends on a number of factors, including the demand for and supply of crude 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 midstream operators. 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.

Our crude oil, natural gas and NGLs are sold in a limited number of geographic markets so an oversupply in any of those areas could have a material negative effect on the price we receive.

Our crude oil, natural gas and NGLs are sold in a limited number of geographic markets and each has a generally fixed amount of storage and processing capacity. As a result, if such markets become oversupplied with crude oil, natural gas and/or NGLs, it could have a material negative effect on the prices we receive for our products and therefore an adverse effect on our financial condition and results of operations. Variances in quality may also cause differences in the value received for our products. Additionally, the refining capacity in the U.S. Gulf Coast is insufficient to refine all of the light sweet crude oil being produced in the United States. The United States imports heavy crude oil and exports light crude oil to utilize the U.S. Gulf Coast refineries that have more heavy refining capacity. If light sweet crude oil production remains at current levels or continues to increase, demand for our light crude oil production could result in widening price discounts to the world crude prices and potential shut in or reduction of production due to a lack of sufficient markets despite the lift on prior restrictions on the exporting of crude oil and natural gas from the United States.

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 42% of our estimated net proved reserves were classified as proved undeveloped as of December 31, 2019. 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.

Unless we replace our crude 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 crude 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. Additionally, certain of our insurance policies also provide coverage to OMP and as a result, a claim by OMP against one of our shared insurance policies may reduce the remaining amount of coverage available to us. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our crude oil and natural gas E&P activities are subject to all of the operating risks associated with drilling for and producing crude oil and natural gas, including the possibility of:

- environmental hazards, such as natural gas leaks, crude 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, such as hydrogen sulfide, 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 2019 and prior years and may do so again in the future.

For the years ended December 31, 2019 and 2018, we incurred a net loss of $128.2 million and $35.3 million, respectively. 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. 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 2020 of approximately $685 million to $715 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 crude 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.

Drilling locations that we decide to drill may not yield crude 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 crude 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 crude oil or natural gas will be present or, if present, whether crude oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of crude 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 the 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, crude 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 in 2018 represented our initial expansion outside of the Williston Basin, and we may encounter new obstacles operating in different 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 crude 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, 2019, approximately 97% and 71% of our total net acreage in the Williston Basin and the 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, 2019, we had 8,809 net acres expiring in 2020, 2,536 net acres expiring in 2021 and 797 net acres expiring in 2022 in the Williston Basin and the 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 crude 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, 2019, 2018 and 2017, we recorded non-cash impairment charges of $5.4 million, $0.9 million and $6.9 million, respectively, on our unproved properties due to expiring leases, periodic assessments and drilling plan uncertainty on certain acreage of our unproved properties.

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

Our crude oil and natural gas E&P operations, midstream operations, 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, 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. Since that time, the EPA has issued area designations with respect to ground-level ozone and has 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 crude 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 crude oil and natural gas production and transportation. These laws and regulations include regulation of crude 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 crude 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. Due to recent incidents involving the release of crude 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 crude oil and natural gas drilling operations in certain locations. Any increased regulation or suspension of crude oil and natural gas exploration and production, or revision or reinterpretation of existing laws and regulations, that arise 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 lesser 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 crude 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 crude 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 and NGLs, including from the Bakken shale, 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 and NGL 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 have made or are 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, new operational protocols for trains transporting large volumes of flammable liquids, 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.

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 and more recently in February 2019, PHMSA published a final rule requiring railroads to develop and submit comprehensive crude oil spill response plans for specific route segments traveled by 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. Additionally, the February 2019 final rule requires railroads to establish geographic response zones along various rail routes, ensure that both personnel and equipment are staged and prepared to respond in the event of an accident, and share information about high-hazard flammable train operations with state and tribal emergency response commissions. 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, urge the federal government to strengthen requirements for these operations or otherwise seek to impose more stringent standards on crude oil being transported by rail. For example, in the absence of a current federal standard on the vapor pressure of crude oil transported by rail, the State of Washington passed a law that became effective on July 28, 2019, prohibiting the loading or unloading of crude oil from a rail car in the state unless the crude oil vapor pressure is lower than nine pounds per square inch. In response, the States of North Dakota and Montana filed a preemption application with PHMSA in July 2019, in which the states seek to have PHMSA make an administrative determination and override the Washington State vapor pressure limits. In July 2019, PHMSA published an invitation for public comments on the preemption application, which comment period closed in the latter half of 2019, with no administrative determination yet being released.

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 crude 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 2018 that further harmonize their respective tank car standards, including with respect to tank car approvals and design requirements.

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 or NGLs from the Bakken shale involving crude oil or NGLs 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.

Our E&P and midstream operations are subject to a number of risks arising out of concerns regarding the threat of climate change that could result in increased operating costs and costs of compliance, limit the areas in which crude oil and natural gas production may occur, and reduce demand for the crude oil and natural gas that we produce or provide midstream services for while the physical effects of climate change could disrupt our production or midstream services and cause us to incur significant costs in preparing for or responding to those effects.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. 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 as well as to restrict or eliminate such future emissions. As a result, our operations as well as the operations of our crude oil and natural gas exploration and production customers are subject to a series of regulatory, political, litigation and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, with the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted rules that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources, implement NSPS directing the reduction of methane from certain new, modified, or reconstructed facilities in the crude oil and natural gas sector, and together with the United States Department of Transportation, implement GHG emissions limits on vehicles manufactured for operation in the United States. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there exists the United Nations-sponsored “Paris Agreement,” which is a non-binding agreement for nations to limit their GHG emissions through individually-determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in federal political risks in the United States in the form of pledges made by certain candidates seeking the office of the President of the United States in 2020. Critical declarations made by one or more presidential candidates include proposals to ban hydraulic fracturing of crude oil and natural gas wells and ban new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions to crude oil and natural gas production activities that could be pursued by presidential candidates may include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquefied natural gas export facilities, as well as the rescission of the United States’ withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against the largest crude oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders and bondholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

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 crude oil and natural gas, which could reduce the demand for the crude 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. Additionally, political, financial and litigation risks may result in us and our customers restricting or canceling production activities, incurring liability for infrastructure damages as a result of climatic changes, or impairing the ability to continue to operate in an economic manner, which also could reduce demand for our midstream services. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation.

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 crude 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 crude 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 2016, the United States Geological Survey identified Texas as being among six states with areas of increased rates of induced seismicity that could be attributed to fluid injection or crude oil and natural gas extraction. Since that time, the United States Geological Survey indicates that these rates have decreased in these six states, although concern continues to exist over quakes arising from induced seismic activities. 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 RRC 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 crude oil and natural 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 crude 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 crude 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 crude oil and natural gas commissions or similar agencies, but 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 crude oil and natural gas source category; and published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional crude oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The BLM published a final rule in 2015 that established new or more stringent standards for performing hydraulic fracturing on federal and Indian lands but the BLM rescinded the 2015 rule in late 2017; however, litigation challenging the BLM's decision to rescind the 2015 rule is pending in federal district court. 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, but not adopted, 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. However, the threat of climate change has resulted in increasing political risks in the United States, including climate-related pledges to ban hydraulic fracturing of oil and gas wells being made by certain candidates seeking the office of President of the United States in 2020.

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 adopt certain prohibitions on hydraulic fracturing altogether, following the approach taken by the States of Maryland, New York and Vermont. 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, crude oil and natural gas production activities using hydraulic fracturing techniques. Any, new or more stringent legal restrictions or bans relating to hydraulic fracturing adopted in areas where we operate, or in the future plan to 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 crude oil and natural gas, potentially cause a decrease in the completion of new crude oil and natural gas wells and perhaps even be limited or precluded from drilling wells or in the volume that we are ultimately able to produce from our reserves, 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 under the Obama Administration issued a final rule outlining their position on the federal jurisdictional reach over waters of the United States. In 2017, the EPA and the Corps under the Trump Administration agreed to reconsider the 2015 rule and, thereafter, in October 2019, the agencies published a final rule made effective on December 23, 2019, rescinding the 2015 rule. On January 23, 2020, the two agencies issued a final rule re-defining the Clean Water Act’s jurisdiction over waters of the United States, which redefinition is narrower than found in the 2015 rule. Upon being published in the Federal Register and the passage of 60 days thereafter, the January 23, 2020 final rule will become effective, at which point the United States will be covered under a single regulatory scheme as it relates to federal jurisdictional reach over waters of the United States. However, there remains the expectation that the January 23, 2020 final rule also will be legally challenged in federal district court. 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 crude 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 crude 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 but that could be materially adverse to our business and results of operations.

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 crude 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 hazardous liquid and 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 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 September 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 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 gas pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued an interim rule in 2016 and published a final rule on October 1, 2019 to implement the agency's expanded authority to address such conditions or practices that pose an imminent hazard to life, property or the environment. Because the 2016 Pipeline Safety Act reauthorized PHMSA's hazardous liquid and gas pipeline programs only through September 30, 2019, we anticipate that Congress will issue an updated pipeline safety law in 2020 that will reauthorize those programs through 2023.

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, on October 1, 2019, PHMSA published a final rule for hazardous liquid transmission and gathering pipelines that becomes effective July 1, 2020 and significantly extends and expands the reach of certain PHMSA hazardous liquid pipeline integrity management requirements regardless of the pipeline's proximity to a HCA (for example, integrity assessments at least once every 10 years of onshore, piggable, hazardous liquid pipeline segments located outside of HCAs, and expanded use of leak detection systems beyond HCAs to all regulated hazardous liquid pipelines other than offshore gathering and regulated rural gathering pipelines). The final rule also requires all hazardous liquid pipelines in or affecting a HCA to be capable of accommodating in line inspection tools within the next 20 years unless the basic construction of a pipeline cannot be modified to permit that accommodation. Also, this final rule extends annual, accident, and safety-related conditional reporting requirements to hazardous liquid gravity lines and certain gathering lines and also imposes inspection requirements on hazardous liquid pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes or other similar events that are likely to damage infrastructure. In a second example, in 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for gas pipelines in newly defined MCAs 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 gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. PHMSA has since decided to split its 2016 proposed rule, which has become known as the "gas mega rule," into three separate rulemaking proceedings to facilitate completion. The first of these three rulemakings, relating to onshore gas transmission pipelines, was published as a final rule on October 1, 2019, becomes effective on July 1, 2020, and imposes numerous requirements on such pipelines, including MAOP reconfirmation, the assessment of additional pipeline mileage outside of HCAs (including all MCAs and those Class 3 and Class 4 areas found not to be in HCAs) within 14 years of publication date and at least once every 10 years thereafter, the reporting of exceedances of MAOP, and the consideration of seismicity as a risk factor in integrity management. The remaining rulemakings comprising the gas mega rule are expected to be issued in 2020. 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, the federal Tenth Circuit Court of Appeals, has held that tribal ownership of even a very small fractional interest in an allotted 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 crude oil and natural gas industry is intense, making it more difficult for us to acquire properties, market crude 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, market crude oil and natural gas and secure equipment and trained personnel. Also, there is substantial competition for capital available for investment in the crude 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 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.

Crude oil and natural gas operations in the Williston Basin and the Delaware Basin are adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other crude 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 to a lesser extent. 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 crude oil and natural gas production ($276.6 million in receivables at December 31, 2019), which we market to energy marketing companies, other producers, power generators, local distribution companies, refineries and affiliates and joint interest receivables ($82.1 million at December 31, 2019).

We are subject to credit risk due to the concentration of our crude 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, 2019, sales to Phillips 66 Company accounted for approximately 14% of our total sales from the exploration and production segment. For the year ended 2018, no purchaser accounted for more than 10% of the Company’s total sales from the exploration and production segment. For the year ended December 31, 2017, sales to Shell Trading (US) Company accounted for approximately 16% of our total sales from the exploration and production segment. No other purchasers accounted for more than 10% of our total sales from the exploration and production segment for the years ended December 31, 2019 and 2017. 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.

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, 2019, we recorded $0.2 million in bad debt expense as a result of our assessment that it is probable certain receivables may not be collected.

In addition, our crude 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, 2019, we had derivatives in place with nine counterparties and a total net derivative liability of $18.6 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 crude oil and natural 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 crude 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. The success of an 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 we successfully integrate the assets acquired, 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. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, in crude 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 crude oil and natural 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 crude oil and natural 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 a crude oil or natural 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, crude 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.

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, 2019, we had significant federal and state income tax NOLs, which will begin to expire in 2030 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 may in the future undergo an ownership change under Section 382. If an ownership change 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 OMS 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 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 natural 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 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, Bobcat DevCo and Beartooth DevCo 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 OMP as a defendant, asserting that it was created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On July 2, 2019, Oasis, OPNA, OMS, OMP, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo (collectively "Oasis Entities") counterclaimed against Mirada for a judgment declaring that Oasis Entities are not obligated to purchase, manage, gather, transport, compress, process, market, sell or otherwise handle Mirada's proportionate share of crude oil and gas produced from OPNA-operated wells. The counterclaim also seeks attorney's fees, costs and expenses.

On November 1, 2019, Mirada filed a sixth amended petition that stated that Mirada seeks in excess of $200 million in damages and asserted that OMS is an agent of OPNA and that OPNA, OMS, OMP, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo are agents of Oasis. Mirada also changed its allegation that it may elect a new operator for the subject wells to instead allege that Mirada may remove OPNA as operator.

On November 1, 2019, the Oasis Entities amended their counterclaim against Mirada to include a request for a judgment declaring that a provision in one of the agreements does not incorporate by reference any provisions in a certain participation agreement and joint operating agreement. The additional counterclaim also seeks attorney's fees, costs and expenses. On the same day, the Oasis Entities filed an amended answer asserting additional defenses against Mirada's claims. Mirada may further amend its petition from time to time to assert additional claims as well as defendants.

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 is scheduled for May 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.

We are from time to time involved in legal, governmental and regulatory proceedings that could result in substantial liabilities.

Like other similarly-situated oil and gas companies, we are from time to time involved in various legal, governmental and regulatory proceedings in the ordinary course of business including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims, regulatory compliance matters, disputes with tax authorities and other matters. The outcome of such matters often cannot be predicted with certainty. If our efforts to defend ourselves in legal, governmental and regulatory matters are not successful, it is possible the outcome of one or more such proceedings could result in substantial liability, penalties, sanctions, judgments, consent decrees or orders requiring a change in our business practices, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. Judgments and estimates to determine accruals related to legal, governmental and regulatory proceedings could change from period to period, and such changes could be material.

Disputes or uncertainties may arise in relation to our royalty obligations.

Our production is subject to royalty obligations which may be prescribed by government regulation or by contract. These royalty obligations may be subject to changes in interpretation as business circumstances change and the law in jurisdictions in which we operate continues to evolve. For example, the Supreme Court of North Dakota recently issued an opinion indicating a change in its interpretation of how certain gas royalty payments are calculated under North Dakota law with respect to certain state leases, the impacts of which are still unclear. Such changes in interpretation could have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, such changes in interpretation could result in legal or other proceedings. Please see "We are from time to time involved in legal, governmental and regulatory proceedings that could result in substantial liabilities" for a discussion of risks related to such proceedings.

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 crude 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 crude oil and natural 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 crude oil and natural 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.

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.

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.

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 OMS, 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 natural 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, Bobcat DevCo and Beartooth DevCo 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 OMP as a defendant, asserting that it was created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On July 2, 2019, Oasis, OPNA, OMS, OMP, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo (collectively “Oasis Entities”) counterclaimed against Mirada for a judgment declaring that Oasis Entities are not obligated to purchase, manage, gather, transport, compress, process, market, sell or otherwise handle Mirada’s proportionate share of oil and gas produced from OPNA-operated wells. The counterclaim also seeks attorney’s fees, costs and expenses.

On November 1, 2019, Mirada filed a sixth amended petition that stated that Mirada seeks in excess of $200 million in damages and asserted that OMS is an agent of OPNA and OPNA, OMS, OMP, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo are agents of Oasis. Mirada also changed its allegation that it may elect a new operator for the subject wells to instead allege that Mirada may remove Oasis as operator.

On November 1, 2019, the Oasis Entities amended their counterclaim against Mirada for a judgment declaring that a provision in one of the agreements does not incorporate by reference any provisions in a certain participation agreement and joint operating agreement. The additional counterclaim also seeks attorney’s fees, costs and expenses. On the same day, the Oasis Entities filed an amended answer asserting additional defenses against Mirada’s claims.

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.

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 is scheduled for May 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.

Solomon litigation

On or about August 28, 2019, Oasis Petroleum LLC, a wholly-owned subsidiary of the Company ("OP LLC"), was named as a defendant in the lawsuit styled Andrew Solomon, on behalf of himself and those similarly situated vs. Oasis Petroleum, LLC, pending in the United States District Court for the District of North Dakota. The lawsuit alleged violations of the federal Fair Labor Standards Act (the "FLSA") and Title 29 of the North Dakota Century Code ("Title 29") as the result of OP LLC's alleged practice of paying the plaintiff and similarly situated current and former employees overtime at rates less than required by applicable law, or failing to pay for certain overtime hours worked. The lawsuit requested that: (i) its federal claims be advanced as a collective action, with a class of all Operators, Technicians and all other employees in substantially similar positions employed by OP LLC who were paid hourly for at least one week during the three year period prior to the commencement of the lawsuit, who worked 40 or more hours in at least one workweek and/or eight or more hours on at least one workday; and (ii) its state claims be advanced as a class action, with a class of all operators, technicians, and all other employees in substantially similar positions employed by OP LLC in North Dakota during the two year period prior to the commencement of the lawsuit, who worked 40 or more hours in at least one workweek and/or worked eight or more hours in a day on at least one workday. No motion has been filed for class certification, and the Company cannot predict whether such a motion will be filed or a class certified.

The Company believes that Mr. Solomon's claims are without merit and that OP LLC has complied with its obligations under the FLSA and Title 29. OP LLC has filed an answer denying all of Mr. Solomon's claims and intends to vigorously defend against the claims. The Company cannot predict or guarantee the ultimate outcome or resolutions 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.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market for Registrant's Common Equity. Our common stock is listed on the Nasdaq under the symbol "OAS."

Holders. As of February 19, 2020, the number of record holders of our common stock was 643. Based on inquiry, management believes that the number of beneficial owners of our common stock is approximately 33,090 as of February 19, 2020.

On February 25, 2020, the last sale price of our common stock, as reported on the Nasdaq, was $1.77 per share.

Unregistered Sales of Securities. There were no sales of unregistered securities during the year ended December 31, 2019.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the three months ended December 31, 2019:

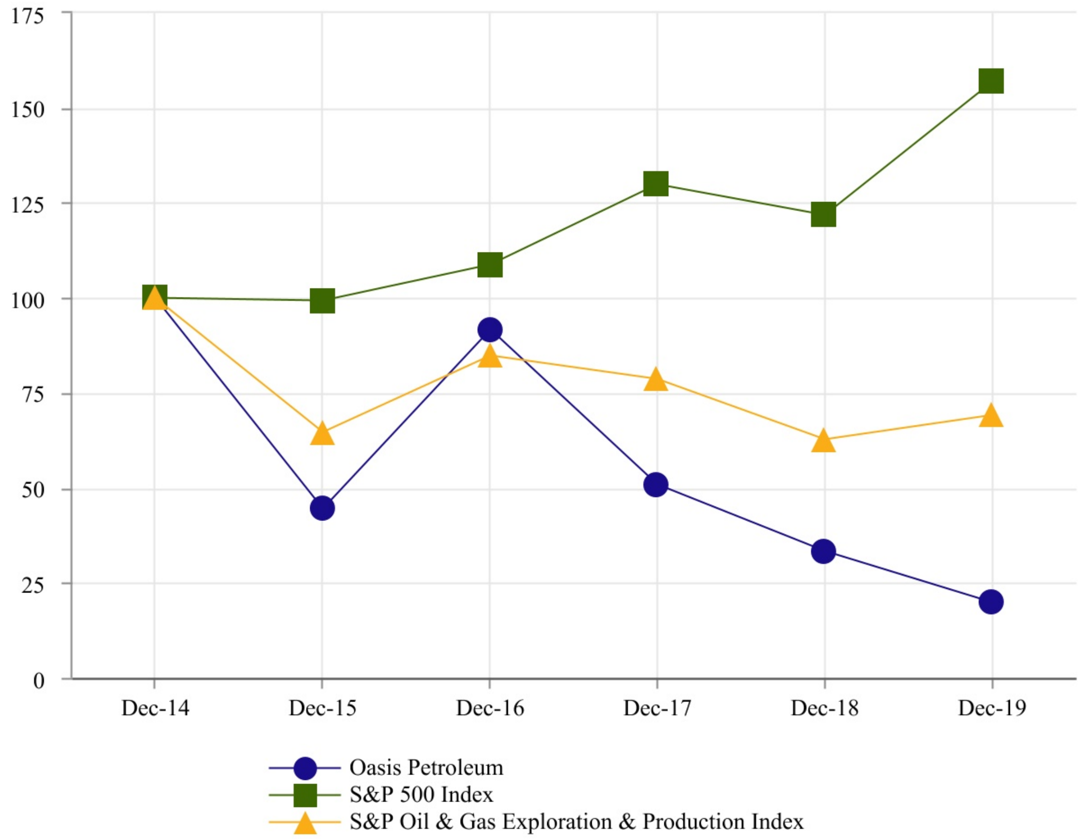
Period	Total Number of Shares Exchanged(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
October 1 – October 31, 2019	15,507	$ 2.83	—	—
November 1 – November 30, 2019	42,601	3.09	—	—
December 1 – December 31, 2019	17,578	2.33	—	—
Total	75,686	$ 2.86	—	—

(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.

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 2014 through December 2019. 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, 2014 at the closing price on such date; and
2. Dividends were reinvested.



Item 6. Selected Financial Data

Set forth below is our summary historical consolidated financial data for the years ended December 31, 2015 through 2019. 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,				
	2019	2018	2017	2016	2015
	(In thousands, except per share data)				
Statement of operations data:					
Revenues:					
Oil and gas revenues	$ 1,408,771	$ 1,590,024	$ 1,034,634	$ 625,233	$ 721,672
Purchased oil and gas sales[1]	408,791	550,344	133,542	10,272	—
Midstream revenues[1]	212,208	120,504	72,752	35,406	23,769
Well services revenues	41,974	61,075	52,791	33,754	44,294
Total revenues	2,071,744	2,321,947	1,293,719	704,665	789,735
Expenses:					
Lease operating expenses	223,384	193,912	177,134	135,444	144,481
Midstream expenses[1]	62,146	32,758	17,589	9,003	6,198
Well services expenses	28,761	41,200	37,228	20,675	24,782
Marketing, transportation and gathering expenses	128,806	107,193	55,740	30,108	31,610
Purchased oil and gas expenses[1]	409,180	553,461	134,615	10,258	—
Production taxes	112,592	133,696	88,133	56,565	69,584
Depreciation, depletion and amortization	787,192	636,296	530,802	476,331	485,322
Exploration expenses	6,658	27,432	11,600	1,785	2,369
Rig termination[2]	384	—	—	—	3,895
Impairment	10,257	384,228	6,887	4,684	46,109
General and administrative expenses	143,506	121,346	91,797	89,342	89,549
Total operating expenses	1,912,866	2,231,522	1,151,525	834,195	903,899
Gain (loss) on sale of properties	(4,455)	28,587	1,774	(1,303)	—
Operating income (loss)	154,423	119,012	143,968	(130,833)	(114,164)
Other income (expense)					
Net gain (loss) on derivative instruments	(106,314)	28,457	(71,657)	(105,317)	210,376
Interest expense, net of capitalized interest	(176,223)	(159,085)	(146,837)	(140,305)	(149,648)
Gain (loss) on extinguishment of debt	4,312	(13,848)	—	4,741	—
Other income (expense)	440	121	(1,332)	160	(2,935)
Total other income (expense), net	(277,785)	(144,355)	(219,826)	(240,721)	57,793
Loss before income taxes	(123,362)	(25,343)	(75,858)	(371,554)	(56,371)
Income tax benefit	32,715	5,843	203,304	128,538	16,123
Net income (loss) including non-controlling interests	(90,647)	(19,500)	127,446	(243,016)	(40,248)
Less: Net income attributable to non-controlling interests[3]	37,596	15,796	3,650	—	—
Net income (loss) attributable to Oasis	$ (128,243)	$ (35,296)	$ 123,796	$ (243,016)	$ (40,248)
Earnings (loss) per share:					
Basic	$ (0.41)	$ (0.11)	$ 0.53	$ (1.32)	$ (0.31)
Diluted	(0.41)	(0.11)	0.52	(1.32)	(0.31)

(1) For the year ended December 31, 2018, midstream revenues and midstream expenses have been adjusted to include $1.5 million and $0.8 million, respectively, for certain sales and expenses which were previously recognized in purchased oil and gas sales and purchased oil and gas expenses, respectively, on our Consolidated Statements of Operations.

(2) During the years ended December 31, 2019 and 2015, we elected to early terminate certain drilling rig contracts and recorded rig termination expenses of $0.4 million and $3.9 million, respectively.

(3) 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, 2018. See Note 3 to our consolidated financial statements for more information with respect to OMP.

	At December 31,				
	2019	**2018**	**2017**	**2016**	**2015**
			(In thousands)		
Balance sheet data:					
Cash and cash equivalents	$ 20,019	$ 22,190	$ 16,720	$ 11,226	$ 9,730
Property, plant and equipment, net	6,977,776	7,027,109	6,173,486	5,919,567	5,218,242
Total assets[(1)]	7,499,253	7,626,142	6,622,929	6,178,632	5,649,375
Long-term debt	2,711,573	2,735,276	2,097,606	2,297,214	2,302,584
Total stockholders' equity	3,837,081	3,918,880	3,513,579	2,923,157	2,319,342

(1) Upon adoption of Accounting Standards Codification 842, *Leases*, in 2019, we recognized operating and finance lease ROU assets of $31.1 million and $6.0 million, respectively. See Note 20 to our consolidated financial statements for a description of our operating and finance leases.

	Year ended December 31,				
	2019	**2018**	**2017**	**2016**	**2015**
			(In thousands)		
Other financial data:					
Net cash provided by operating activities	$ 892,853	$ 996,421	$ 507,876	$ 228,018	$ 359,815
Net cash used in investing activities	(828,756)	(1,613,536)	(714,760)	(1,070,828)	(479,148)
Net cash provided by (used in) financing activities	(66,268)	622,585	212,378	844,306	83,252

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 crude 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 crude 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. Oasis Petroleum North America LLC ("OPNA") and Oasis Petroleum Permian LLC ("OP Permian") conduct our domestic crude oil and natural gas E&P activities and own our proved and unproved oil and gas properties located in the North Dakota and Montana regions of the Williston Basin and the Texas region of the Delaware Basin, respectively. In addition to our exploration and production segment, we also operate a midstream business through Oasis Midstream Partners LP ("OMP" or "Oasis Midstream") and Oasis Midstream Services LLC ("OMS"). OMP is a growth-oriented, fee-based master limited partnership that develops and operates a diversified portfolio of midstream assets. We own a substantial majority of the general partner and a majority of the outstanding units of OMP. As of December 31, 2019, we operated a well services business through Oasis Well Services LLC ("OWS"). In March 2020, we intend to transition our well fracturing services from OWS to a third-party provider who will provide services to us under a long-term agreement. We believe this will result in continued quality service, while allowing us to focus on our core operations.

We built our Williston Basin and Delaware Basin assets through acquisitions and development activities. 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, and we have historically acquired properties that we believe will meet or exceed our rate of return criteria. 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.

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 crude oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for crude oil and natural gas, as well as market uncertainty, economic conditions and a variety of additional factors. Since the inception of our crude oil and natural gas activities, commodity prices have experienced significant fluctuations and may fluctuate widely in the future. As a result of current market conditions, we continue to concentrate our drilling activities in certain areas that are the most economical in the Williston and Delaware Basins, and we are focused on delivering moderate growth while maintaining capital spending within internally generated cash flows. A substantial or extended decline in prices for crude oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of crude 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 crude oil, natural gas and NGLs, we manage our commodities marketing activities in-house, which enables us to market and sell our crude oil, natural gas and NGLs to a broad array of potential purchasers. We enter into crude oil, natural gas and NGL 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 crude oil, natural gas and NGL 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, 91% of our gross operated crude 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 crude oil prices and average price differentials are shown in the tables below.

	2019				
	Q1	Q2	Q3	Q4	Year ended December 31, 2019
Average Realized Crude Oil Prices ($/Bbl)(1)	$ 53.52	$ 58.87	$ 55.12	$ 53.66	$ 55.27
Average Price Differential ($/Bbl)(2)	$ 1.30	$ 0.96	$ 1.30	$ 3.23	$ 1.68
Average Price Differential Percentage(2)	2 %	2 %	2 %	6 %	3 %

	2018				
	Q1	Q2	Q3	Q4	Year ended December 31, 2018
Average Realized Crude 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 Crude 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 %

(1) Realized crude oil prices do not include the effect of derivative contract settlements.
(2) Price differential reflects the difference between realized crude oil prices and NYMEX 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 NYMEX WTI due to transportation costs and takeaway capacity. In the past, there have been periods when this discount has substantially increased due to crude 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 crude oil transportation out of the Williston Basin and improved our price differentials received at the lease. In 2015, our price differentials relative to NYMEX WTI strengthened as new pipelines opened to eastern Canada and U.S. markets and transportation on rail gradually declined. In the Williston Basin, our crude oil price differentials averaged approximately $1.65 per barrel discount to NYMEX WTI during 2019. In the Delaware Basin, price differentials have improved throughout the year due to new pipelines coming online, averaging close to $0.20 above NYMEX WTI during the fourth quarter of 2019 as compared to more than $5.00 per barrel below NYMEX WTI in the first quarter of 2019. Expansions of pipelines will continue to improve differentials and provide ample takeaway for our Delaware Basin production.

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 crude oil prices, we are planning to decrease our well completions from 67 gross (41.6 net) operated wells in the Williston Basin in 2019 to approximately 45 to 55 gross operated wells in 2020. In the Delaware Basin, we are planning to increase in well completions from 11 gross (9.9 net) operated wells in 2019 to approximately 20 to 25 gross operated wells in 2020. Additionally, we have the ability to control the pace of completions to allow for additional financial flexibility. In 2019, we wrote off $0.6 million of leases that we did not expect to develop before their 2020 contract expirations, as we continue to focus our 2020 drilling activities in our core acreage in the Williston Basin and the Delaware Basin.

Our 2019, 2018 and 2017 activities included development and exploration drilling in the Williston Basin with activities in the Delaware Basin starting in 2018 and through 2019. 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 286.4 MMBoe of estimated net proved reserves with a PV-10 of $2,934.4 million and a Standardized Measure of $2,844.4 million at December 31, 2019, 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 and 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. Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for crude 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, 2019, 2018 and 2017 were $55.85 per Bbl for crude oil and $2.62 per MMBtu for natural gas, $65.66 per Bbl for crude oil and $3.16 per MMBtu for natural gas and $51.34 per Bbl for crude oil and $2.99 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 crude 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.

Expected forward commodity prices and estimates of future production also play a significant role in determining impairment of proved oil and gas properties. In 2018, we recorded impairment charges of $134.8 million 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, 2019. As a result of lower commodity prices and lower recoverable reserves in the Williston Basin and the Delaware Basin and their impact on our estimated future cash flows, we have continued to review our proved oil and gas properties for impairment. As of December 31, 2019, the excess of our estimated undiscounted future cash flows over the carrying value of our proved oil and gas properties was $186.1 million in the Williston Basin and $430.7 million in the Delaware Basin. Our estimated undiscounted future cash flows include the cost benefits from consolidating our midstream and well services business segments as well as the impact of transitioning our well fracturing services from OWS to a third-party provider in March 2020. If we discontinued or no longer had a controlling financial interest in the operations of the midstream business segment, our expected future costs would increase, which may cause the estimated undiscounted future cash flows to decline below the carrying value of our proved oil and gas properties.

The underlying commodity prices included in our estimated undiscounted cash flows were determined using NYMEX forward strip prices for five years as of December 31, 2019, escalating 3% per year thereafter. Our estimated undiscounted future cash flows also included a 3% inflation factor applied to the future operating and development costs after five years and every year thereafter. Expected future commodity prices have decreased since December 31, 2019, and we may record a proved property impairment charge in 2020. If expected future commodity prices decline by approximately 2% as compared to December 31, 2019, holding all other factors constant, the estimated undiscounted future cash flows may not exceed the carrying value of our proved oil and gas properties in the Williston Basin, and if expected future commodity prices decline by approximately 20% as compared to December 31, 2019, holding all other factors constant, the estimated undiscounted future cash flows may not exceed the carrying value of our proved oil and gas properties in the Delaware Basin.

If our estimated future cash flows decline below the carrying value of our proved oil and gas properties, we may recognize proved property impairment charges in the future for the Williston Basin and the Delaware Basin, and such impairment charges could exceed $2 billion and $455 million, respectively, assuming a discount rate of 10%. This sensitivity analysis decreased the expected future prices of both crude oil and natural gas, but a decline in the realized price of either commodity, an increase to costs or an increase in discount rate greater than those described above may independently impact our estimated future cash flows.

Highlights

- Our production volumes averaged 88,061 Boepd (71.0% oil) for the year ended December 31, 2019.
- We participated in 130 gross (52.1 net) wells that were completed and placed on production, and, as operator, we completed and placed on production 78 gross (51.5 net) operated wells, including 67 gross (41.6 net) operated wells in the Williston Basin and 11 gross (9.9 net) operated wells in the Delaware Basin, while investing $594.2 million of E&P capital expenditures, which excludes acquisitions, other capital and midstream capital, during 2019.
- Our crude oil differentials improved to $1.68 off of NYMEX WTI in 2019.
- Net cash provided by operating activities was $892.9 million for the year ended December 31, 2019. Adjusted EBITDA, a non-GAAP financial measure, was $1,039.5 million for the year ended December 31, 2019. 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 crude oil and natural gas revenues are derived from the sale of crude 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 primarily derived from the sale of crude oil and natural gas purchased through our marketing activities primarily to optimize transportation costs or for blending at our crude oil terminal. Revenues and expenses from crude oil and natural gas 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 crude oil or natural 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 natural gas gathering and processing, produced and flowback water gathering and disposal, crude oil gathering and transportation and fresh water sales. Our well services revenues are derived from well services, product sales and equipment rentals. A majority of our midstream revenues and substantially 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.

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

	Year ended December 31,		
	2019	2018	2017
Operating results (in thousands)			
Revenues			
Crude oil revenues	$ 1,261,413	$ 1,425,409	$ 912,806
Natural gas revenues	147,358	164,615	121,828
Purchased oil and gas sales(1)	408,791	550,344	133,542
Midstream revenues(1)	212,208	120,504	72,752
Well services revenues	41,974	61,075	52,791
Total revenues	$ 2,071,744	$ 2,321,947	$ 1,293,719
Production data			
Williston Basin			
Crude oil (MBbls)	20,722	21,786	18,818
Natural gas (MMcf)	52,813	40,550	31,946
Oil equivalents (MBoe)	29,524	28,544	24,143
Average daily production (Boe per day)	80,889	78,203	66,144
Delaware Basin			
Crude oil (MBbls)	2,102	1,264	—
Natural gas (MMcf)	3,093	1,880	—
Oil equivalents (MBoe)	2,618	1,578	—
Average daily production (Boe per day)	7,172	4,322	—
Average sales prices			
Crude oil, without derivative settlements (per Bbl)	$ 55.27	$ 61.84	$ 48.51
Crude oil, with derivative settlements (per Bbl)(2)	55.89	52.65	47.99
Natural gas, without derivative settlements (per Mcf)(3)	2.64	3.88	3.81
Natural gas, with derivative settlements (per Mcf)(2)(3)	2.72	3.84	3.86

(1) For the year ended December 31, 2018, midstream revenues have been adjusted to include $1.5 million for certain sales which were previously recognized in purchased oil and gas sales on our Consolidated Statements of Operations.

(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 NGLs.

Year ended December 31, 2019 as compared to year ended December 31, 2018

Crude oil and natural gas revenues. Our crude oil and natural gas revenues decreased $181.2 million, or 11%, to $1,408.8 million during the year ended December 31, 2019 as compared to the year ended December 31, 2018. This decrease was primarily driven by a $204.2 million decrease due to lower crude oil and natural gas sales prices, coupled with a $12.5 million decrease driven by lower crude oil production amounts sold year over year. These decreases were partially offset by a $35.5 million increase driven by higher natural gas production amounts sold year over year. Average crude oil sales prices, without derivative settlements, decreased by $6.57 per barrel to an average of $55.27 per barrel, and average natural gas sales prices, without derivative settlements and which include the value for natural gas and NGLs, decreased by $1.24 per Mcf to an average of $2.64 per Mcf for the year ended December 31, 2019 as compared to the year ended December 31, 2018. Average daily production sold increased by 5,536 Boe per day to 88,061 Boe per day during the year ended December 31, 2019 as compared to the year ended December 31, 2018, primarily due to an increase in natural gas production, offset by a decrease in crude oil production. The increase in average daily production sold was primarily a result of our well completions during the year, offset by our divestitures of various upstream packages. During the year ended December 31, 2019, we completed 42.1 total net wells in the Williston Basin and 10.0 total net wells in the Delaware Basin.

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, decreased $141.6 million to $408.8 million for the year ended December 31, 2019 as compared to the year ended December 31, 2018, primarily due to lower crude oil volumes purchased and sold in the Williston Basin.

Midstream revenues. Midstream revenues were $212.2 million for the year ended December 31, 2019, which was a $91.7 million increase year over year. This increase was primarily driven by a $69.4 million increase related to higher natural gas sales resulting from the commencement of third-party natural gas purchase arrangements in the fourth quarter of 2018, coupled with a $20.6 million increase related to higher natural gas volumes gathered, compressed and processed as a result of the start-up of our second natural gas processing plant in Wild Basin during the fourth quarter of 2018.

Well services revenues. Well services revenues decreased by $19.1 million to $42.0 million for the year ended December 31, 2019 as compared to the year ended December 31, 2018, which was primarily attributable to a $9.4 million decrease in well completion revenues due to decreased activity as a result of reducing to one fracturing crew in the third quarter of 2019, coupled with an $8.1 million decrease in product sales to third parties and a $1.5 million decrease in equipment rentals.

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

For the comparison of the years ended December 31, 2018 and 2017, refer to “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our Annual Report on Form 10-K for the year ended December 31, 2018, filed with the SEC on March 1, 2019.

Expenses and other income

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

	Year ended December 31,		
	2019	2018	2017
	(In thousands, except per Boe of production)		
Operating expenses			
Lease operating expenses	$ 223,384	$ 193,912	$ 177,134
Midstream expenses[(1)]	62,146	32,758	17,589
Well services expenses	28,761	41,200	37,228
Marketing, transportation and gathering expenses	128,806	107,193	55,740
Purchased oil and gas expenses[(1)]	409,180	553,461	134,615
Production taxes	112,592	133,696	88,133
Depreciation, depletion and amortization	787,192	636,296	530,802
Exploration expenses	6,658	27,432	11,600
Rig termination	384	—	—
Impairment	10,257	384,228	6,887
General and administrative expenses	143,506	121,346	91,797
Total operating expenses	1,912,866	2,231,522	1,151,525
Gain (loss) on sale of properties	(4,455)	28,587	1,774
Operating income	154,423	119,012	143,968
Other income (expense)			
Net gain (loss) on derivative instruments	(106,314)	28,457	(71,657)
Interest expense, net of capitalized interest	(176,223)	(159,085)	(146,837)
Gain (loss) on extinguishment of debt	4,312	(13,848)	—
Other income (expense)	440	121	(1,332)
Total other expense, net	(277,785)	(144,355)	(219,826)
Loss before income taxes	(123,362)	(25,343)	(75,858)
Income tax benefit	32,715	5,843	203,304
Net income (loss) including non-controlling interests	(90,647)	(19,500)	127,446
Less: Net income attributable to non-controlling interests[(2)]	37,596	15,796	3,650
Net income (loss) attributable to Oasis	$ (128,243)	$ (35,296)	$ 123,796
Costs and expenses (per Boe of production)			
Lease operating expenses	$ 6.95	$ 6.44	$ 7.34
Marketing, transportation and gathering expenses	4.01	3.56	2.31
Production taxes	3.50	4.44	3.65

(1) For the year ended December 31, 2018, midstream expenses have been adjusted to include $0.8 million for certain expenses which were previously recognized in purchased oil and gas expenses on our Consolidated Statements of Operations.

(2) 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, 2018. See Note 3 to our consolidated financial statements for more information with respect to OMP.

Year ended December 31, 2019 as compared to year ended December 31, 2018

Lease operating expenses. Lease operating expenses increased $29.5 million to $223.4 million for the year ended December 31, 2019 as compared to the year ended December 31, 2018. This increase was primarily due to higher fixed costs and workover costs, coupled with higher costs associated with operating an increased number of producing wells as a result of our well completions during the year ended December 31, 2019. We completed and placed on production 52.1 total net wells, including

42.1 total net wells in the Williston Basin and 10.0 total net wells in the Delaware Basin, during the year ended December 31, 2019. Lease operating expenses per Boe increased from $6.44 per Boe to $6.95 per Boe primarily due to the higher aforementioned costs, offset by higher production volumes year over year.

Midstream expenses. Midstream expenses represent third-party working interest owners' share of operating expenses incurred by OMS. The $29.4 million increase for the year ended December 31, 2019 as compared to the year ended December 31, 2018 was primarily related to a $19.5 million increase in natural gas purchases from third parties, coupled with a $10.9 million increase in natural gas gathering, compression and processing expenses driven by increased production as a result of the start-up of our second natural gas processing plant in Wild Basin during the fourth quarter of 2018 and increased costs related to downtime at our natural gas processing complex during 2019. These increases were partially offset by a $1.5 million decrease related to lower produced and flowback water operating expenses year over year.

Well services expenses. Well services expenses represent third-party working interest owners' share of completion service costs, cost of goods sold and operating expenses incurred by OWS. The $12.4 million decrease for the year ended December 31, 2019 as compared to the year ended December 31, 2018 was primarily attributable to a $6.6 million decrease in well completion expenses due to decreased activity as a result of reducing to one fracturing crew in the third quarter of 2019, coupled with a $5.8 million decrease in product sales to third parties.

Marketing, transportation and gathering ("MT&G") expenses. MT&G expenses increased $21.6 million year over year, or a $0.45 increase per Boe, which was primarily attributable to higher natural gas gathering and processing expenses due to additional well connections on our midstream infrastructure and our second natural gas processing plant, coupled with higher oil gathering and transportation expenses related to increased throughput on the Dakota Access Pipeline to market our equity barrels. Cash MT&G expenses, which excludes non-cash valuation adjustments, on a per Boe basis increased to $3.93 for the year ended December 31, 2019 as compared to $3.41 for the year ended December 31, 2018 primarily due to the higher aforementioned costs. For a definition of Cash MT&G and a reconciliation of MT&G to Cash MT&G, see "Non-GAAP Financial Measures" below.

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, decreased $144.3 million to $409.2 million for the year ended December 31, 2019 as compared to December 31, 2018 primarily due to lower crude oil volumes purchased and sold in the Williston Basin.

Production taxes. Our production taxes for the years ended December 31, 2019 and 2018 were 8.0% and 8.4%, respectively, as a percentage of crude oil and natural gas sales. The production tax rate decreased year over year primarily due to a lower crude oil production mix, coupled with the addition of Delaware Basin assets, which bear a lower average production tax rate than the Williston Basin assets. North Dakota's natural gas production tax is $0.0712 per Mcf, while its crude oil tax structure is based on a 5% production tax and a 5% crude oil extraction tax, resulting in a combined tax rate of 10% on crude oil revenues.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $150.9 million to $787.2 million for the year ended December 31, 2019 as compared to the year ended December 31, 2018. This increase was primarily due to production increases from our wells completed during 2019, coupled with an increase in the average DD&A rate to $24.49 per Boe for the year ended December 31, 2019 as compared to $21.12 per Boe for the year ended December 31, 2018. The increase in the DD&A rate was primarily due to lower recoverable reserves in the Williston Basin and the Delaware Basin, coupled with higher well costs in the Delaware Basin.

Exploration expenses. Exploration expenses decreased $20.7 million to $6.7 million for the year ended December 31, 2019 as compared to the year ended December 31, 2018. This decrease was primarily due to lower write-off costs of $15.1 million related to exploratory well locations that are no longer in our current development plan.

Impairment. During the years ended December 31, 2019 and 2018, we recorded total impairment charges of $10.3 million and $384.2 million, respectively. During the year ended December 31, 2019, we pursued an exit from the well services business and recorded an impairment loss of $4.4 million to adjust the carrying value of certain inventory and equipment held for sale to their estimated fair value (see Note 12—Assets Held for Sale). There were no impairment charges of proved oil and gas or other properties recorded during the year ended December 31, 2019. 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). As a result of expiring leases, periodic assessments and drilling plan uncertainty on certain acreage of our unproved properties, we recorded an impairment loss on our unproved oil and gas properties of $5.4 million and $0.9 million for the years ended December 31, 2019 and 2018, respectively, related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. Due to fluctuating commodity prices, we recorded an impairment loss of $0.5 million to adjust the carrying value of our long-term inventory to its net realizable value during the year ended December 31, 2019. There were no such impairment charges recorded during year ended December 31, 2018.

General and administrative ("G&A") expenses. Our G&A expenses increased $22.2 million to $143.5 million for the year ended December 31, 2019 from $121.3 million for the year ended December 31, 2018. E&P G&A increased $16.2 million year over year primarily due to a $20.0 million loss accrual, which we believe is the estimable amount of loss that could potentially be incurred from our pending legal proceedings based upon currently available information (see Note 22—Commitments and Contingencies). This increase was coupled with increased costs related to employee compensation expenses as a result of organizational growth during the first half of 2019, coupled with severance expenses related to a reduction in force during the third quarter of 2019, and partially offset by the decrease in costs related to the Permian Basin Acquisition, which were incurred during the year ended December 31, 2018. OMS G&A increased $2.5 million year over year primarily due to increased shared services expenses as a result of the growth of our midstream business. OWS G&A increased $3.4 million due to severance expenses resulting from a reduction in force to one fracturing crew during the third quarter of 2019. Consolidated G&A expenses included non-cash amortization for equity-based compensation of $33.6 million and $29.3 million in 2019 and 2018, respectively. Our full-time employee headcount decreased 16% year over year.

Gain (loss) on sale of properties. For the year ended December 31, 2019, we recognized a $4.5 million net loss primarily due to completing the final closing statements for the sale of non-strategic oil and gas properties and certain other property and equipment in the Williston Basin. For the year ended December 31, 2018, we recognized a $28.6 million net gain related to the sale of three separate divestitures to sell certain non-strategic oil and gas properties in the Williston Basin (see Note 11—Divestitures).

Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip crude oil and natural gas price changes, we incurred a $106.3 million net loss on derivative instruments, including net cash settlement receipts of $19.1 million, for the year ended December 31, 2019, and 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. 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, net of capitalized interest. Interest expense increased $17.1 million to $176.2 million for the year ended December 31, 2019 as compared to the year ended December 31, 2018 primarily due to a $10.0 million increase in interest expense related to our borrowings under our OMP Credit Facility, coupled with a decrease in capitalized interest of $5.3 million due to lower costs for work in progress assets year over year. For the year ended December 31, 2019, the weighted average debt outstanding under the Oasis Credit Facility and the OMP Credit Facility was $511.5 million and $392.1 million, respectively, and the weighted average interest rate incurred on the outstanding borrowings was 4.0% and 4.1%, respectively. For the year ended December 31, 2018, the weighted average debt outstanding under the Oasis Credit Facility and the OMP Credit Facility was $554.7 million and $166.2 million, respectively, and the weighted average interest rate incurred on the outstanding borrowings was 3.9% and 3.8%, respectively. We capitalized $12.0 million and $17.2 million of interest costs for the years ended December 31, 2019 and 2018, respectively, which will be amortized over the life of the related assets.

Gain (loss) on extinguishment of debt. During the year ended December 31, 2019, we repurchased an aggregate principal amount of $56.8 million of our outstanding senior unsecured notes and senior unsecured convertible notes for an aggregate cost of $45.8 million. For the year ended December 31, 2019, we recognized a pre-tax gain related to the repurchase of $4.3 million, which included the write-off of unamortized deferred financing costs and unamortized debt discount of $6.7 million. 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.

Income tax benefit. Our income tax benefit for the years ended December 31, 2019 and 2018 was recorded at 26.5% and 23.1%, respectively, of pre-tax loss. The 3.4% increase in the effective tax rate recorded is primarily due to (i) the impact of non-deductible executive compensation, (ii) equity-based compensation shortfalls in 2019 exceeding the equity-based compensation shortfalls in 2018, (iii) impacts from the Tax Act recorded in 2018 and (iv) the increase in valuation allowance recorded against our Montana net operating loss carryforwards in 2018. This was partially offset by (i) the impact of non-controlling interests and (ii) the impact of a change in the state rate at which deferred taxes are recorded in 2018.

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

For the comparison of the years ended December 31, 2018 and 2017, refer to "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2018, filed with the SEC on March 1, 2019.

Liquidity and Capital Resources

Our primary sources of liquidity as of the date of this report have been cash flows from operations, proceeds from the sale of certain non-strategic oil and gas properties, cash settlements of derivative contracts and borrowings under a $1,300.0 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 $575.0 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”). Our primary uses of cash have been for the development and acquisition of oil and gas properties and midstream infrastructure, repurchases of our Senior Notes (as defined below), distributions to non-controlling interests and interest payments on outstanding debt. We continually monitor potential capital sources, including equity and debt financings and potential asset monetization opportunities, in order to enhance liquidity and decrease leverage. Although we have financial flexibility with our cash balance and the ability to draw on our Revolving Credit Facilities, we continue to be committed to our capital discipline strategy of investing within our cash flows from operations and cash settlements of derivative contracts.

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

	Year ended December 31, 2019	2018	2017
		(In thousands)	
Net cash provided by operating activities	$ 892,853	$ 996,421	$ 507,876
Net cash used in investing activities	(828,756)	(1,613,536)	(714,760)
Net cash provided by (used in) financing activities	(66,268)	622,585	212,378
Net change in cash and cash equivalents	$ (2,171)	$ 5,470	$ 5,494

Our cash flows depend on many factors, including the price of crude oil and natural gas and the success of our development and exploration activities as well as future acquisitions. Prices for crude oil began to show upward movements during 2017 and the majority of 2018 resulting in increased cash flows provided by operating activities. In late 2018, crude oil prices declined and have remained relatively flat throughout 2019 resulting in decreased cash flows provided by operating activities for the year ended December 31, 2019. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to mitigate the change in crude oil and natural gas prices on a portion of our production, thereby mitigating our exposure to crude oil and natural gas price declines, but these transactions may also limit our cash flow in periods of rising crude oil and natural gas prices. As of December 31, 2019, our derivative contracts in place cover 16.6 MMBbls of crude oil in 2020 and 2021.

Our existing Revolving Credit Facilities provide additional liquidity. The Oasis Credit Facility has a current borrowing base of $1,300.0 million and an elected commitment amount of $1,100.0 million. The next redetermination of the borrowing base for the Oasis Credit Facility is scheduled for April 1, 2020. The OMP Credit Facility has a current borrowing capacity of $575.0 million.

We believe we have adequate liquidity to fund planned 2020 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 $892.9 million, $996.4 million and $507.9 million for the years ended December 31, 2019, 2018 and 2017, respectively. The decrease in cash flows provided by operating activities for the year ended December 31, 2019 as compared to 2018 was primarily the result of an 11% decrease in realized crude oil prices, coupled with a 32% decrease in realized natural gas prices and a 1% decrease in crude oil production. These decreases were partially offset by a 32% increase in natural gas production. 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 crude oil production, a 27% increase in realized prices for crude oil, a 33% increase in natural gas production and a 2% increase in realized prices for natural gas.

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 $165.5 million at December 31, 2019 due to the impact of decreases in the forward commodity price curve on our short-term derivative instruments and decreases in accounts receivable, partially offset by decreases in accrued liabilities for crude oil and natural gas purchases used to optimize transportation costs or for blending and accrued liabilities for G&A expenses. However, we believe we have adequate liquidity to meet our working capital requirements. As of December 31, 2019, we had $882.7 million of liquidity available, including $20.0 million in cash and cash equivalents and $862.7 million of aggregate unused borrowing capacity available under our Revolving Credit Facilities. As of December 31, 2018, we had a working capital deficit of $57.6 million.

Cash flows used in investing activities

We had net cash flows used in investing activities of $828.8 million, $1,613.5 million and $714.8 million for the years ended December 31, 2019, 2018 and 2017, respectively, primarily as a result of our capital expenditures for acquisition, drilling and development costs. The decrease in cash used in investing activities for the year ended December 31, 2019 as compared to the year ended December 31, 2018 was primarily attributable to a decrease in cash used for acquisitions year over year, and a 24% decrease in cash capital expenditures primarily for drilling and development costs. Net cash used in investing activities during the year ended December 31, 2019 was primarily attributable to $869.2 million in capital expenditures, coupled with $21.0 million in acquisitions, partially offset by $42.4 million for proceeds from sale of properties and $19.1 million for derivative settlements received as a result of lower crude oil prices. 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 for 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.

Expenditures for the acquisition and development of oil and gas properties are the primary use of our capital resources. Our capital expenditures for the years ended December 31, 2019, 2018 and 2017 are summarized in the following table:

	Year ended December 31,		
	2019	2018	2017
		(In thousands)	
Capital expenditures			
E&P	$ 594,217	$ 942,179	$ 517,329
Well services	282	7,831	12,537
Other capital expenditures(1)	15,478	23,947	17,215
Total capital expenditures before acquisitions and midstream	$ 609,977	$ 973,957	$ 547,081
Midstream(2)	212,381	277,626	235,090
Total capital expenditures before acquisitions	822,358	1,251,583	782,171
Acquisitions	21,010	951,870	54,033
Total capital expenditures(3)	$ 843,368	$ 2,203,453	$ 836,204

(1) Other capital expenditures includes administrative capital and capitalized interest.
(2) Midstream capital expenditures attributable to OMP were $198.6 million and $116.6 million for the years ended December 31, 2019 and 2018, respectively.
(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 2019, we spent $843.4 million on capital expenditures, which represented a 62% decrease as compared to the $2,203.5 million spent during 2018. This decrease was primarily due to a $930.9 million decrease in acquisitions year over year. Excluding acquisitions, capital expenditures decreased 34% as compared to 2018. This decrease was attributable to decreased drilling and completion activity as a result of lower commodity prices in 2019, coupled with lower capital expenditures for midstream as a result of completing the second natural gas processing plant in Wild Basin during the fourth quarter of 2018.

On February 22, 2019, we entered into a memorandum of understanding (the “MOU”) with OMP regarding the funding of Bobcat DevCo’s expansion capital expenditures for the 2019 calendar year (the “2019 Capital Expenditures Arrangement”).

Pursuant to the MOU, in exchange for increasing its percentage ownership interest in Bobcat DevCo, OMP agreed to make up to $80.0 million of the capital contributions to Bobcat DevCo that OMS would otherwise have been required to contribute. During the year ended December 31, 2019, OMP made capital contributions to Bobcat DevCo pursuant to the 2019 Capital Expenditures Arrangement of $73.0 million. As a result, OMS's ownership interest in Bobcat DevCo decreased from 75% as of December 31, 2018 to 64.7% as of December 31, 2019. The 2019 Capital Expenditures Arrangement ended on December 31, 2019.

As a result of current crude oil prices, we have decreased our planned 2020 capital expenditures as compared to 2019 capital expenditures, excluding acquisitions. We anticipate investing between $685 million and $715 million in 2020 as follows:

	Plan for the year ended December 31, 2020
	(In thousands)
E&P and other capital[(1)]	$575,000 - $595,000
Midstream capital[(2)]	110,000 - 120,000
Total capital expenditures	$685,000 - $715,000

(1) E&P and other capital expenditures includes administrative capital and excludes capitalized interest of approximately $12.5 million.
(2) Midstream capital expenditures include approximately $42 million to $45 million for midstream capital expenditures attributable to Oasis.

While we have planned approximately $685 million to $715 million for total capital expenditures in 2020, 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 2020 capital expenditure plan and to meet our future obligations. However, because the operated wells funded by our 2020 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 crude 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 (used in) financing activities

Net cash provided by (used in) financing activities was $(66.3) million, $622.6 million and $212.4 million for the years ended December 31, 2019, 2018 and 2017, respectively. For the year ended December 31, 2019, net cash used in financing activities was primarily attributable to the repurchase of a portion of our Senior Notes (as defined below) and distributions to non-controlling interests. 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), 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, net of offering costs, and net proceeds from the sale of OMP common units, net of offering costs, partially offset by principal payments on our Revolving Credit Facilities.

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, 2019. 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 (as defined below), of which $1,242.9 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 Notes (as defined below), of which $267.8 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 April 15, 2019, the lenders under the Oasis Credit Facility completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2019, which reaffirmed the borrowing base and the aggregate elected commitment at $1,600.0 million and $1,350.0 million, respectively. In connection with the April 1, 2019 borrowing base redetermination, we entered into the First Amendment to the Third Amended and Restated Credit Agreement to the Oasis Credit Facility, dated April 15, 2019, which, among other things, incorporated the ability for us to request swingline loans subject to a swingline loans sublimit of $50.0 million.

On November 4, 2019, the lenders under the Oasis Credit Facility completed their semi-annual redetermination of the borrowing base scheduled for October 1, 2019. As a result, the borrowing base decreased from $1,600.0 million to $1,300.0 million. The next redetermination of the Oasis Credit Facility's borrowing base is scheduled for April 1, 2020. Additionally, we entered into the third amendment to the Oasis Credit Facility, which among other things, decreased the aggregate elected commitment from $1,350.0 million to $1,100.0 million in conjunction with the redetermination.

As of December 31, 2019, 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 crude 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 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, 2019, we had $337.0 million of borrowings at a weighted average interest rate of 3.5% and $15.1 million of outstanding letters of credit issued under the Oasis Credit Facility, resulting in an unused borrowing capacity of $747.9 million. 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 capacity of $868.0 million. We were in compliance with the financial covenants of the Oasis Credit Facility as of December 31, 2019 and 2018. 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.

OMP Operating LLC revolving line of credit. Through our majority ownership of OMP, we have access to the OMP Credit Facility, which is available to fund working capital and to finance acquisitions and other capital expenditures of OMP. On May 6, 2019, OMP entered into an amendment to the OMP Credit Facility to (i) increase the aggregate amount of commitments from $400.0 million to $475.0 million; (ii) provide for the ability to further increase commitments to $675.0 million; and (iii) add a new lender to the bank group. On August 16, 2019, OMP entered into the third amendment to the OMP Credit Facility to (i) increase the aggregate amount of commitments from $475.0 million to $575.0 million and (ii) provide for the ability to further increase commitments to $775.0 million. As of December 31, 2019, the OMP Credit Facility has an aggregate amount of commitments of $575.0 million and has a maturity date of September 25, 2022.

As of December 31, 2019, we had $458.5 million of borrowings outstanding at a weighted average interest rate of 3.8% and $1.7 million of outstanding letters of credit issued under the OMP Credit Facility, resulting in an unused borrowing capacity of $114.8 million. 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 capacity of $82.0 million.

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). 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, Bighorn DevCo and Panther DevCo. OMP Operating LLC was in compliance with the financial covenants of the OMP Credit Facility at December 31, 2019.

Senior unsecured notes. As of December 31, 2019, our long-term debt includes outstanding senior unsecured note obligations of $1,714.8 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”), $891.0 million of 6.875% senior unsecured notes due March 15, 2022 (the “2022 Notes”), $352.0 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”).

During the fourth quarter of 2019, we repurchased an aggregate principal amount of $24.6 million of our outstanding Senior Notes, consisting of $10.5 million principal amount of the 2022 Notes and $14.1 million principal amount of the 2023 Notes, for an aggregate cost of $22.8 million. As a result of these repurchases, we recognized a pre-tax gain of $1.6 million, which was net of unamortized deferred financing costs write-offs of $0.2 million, and is reflected in gain on extinguishment of debt in our Consolidated Statements of Operations for the year ended December 31, 2019.

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, 2019.

Senior unsecured convertible notes. At December 31, 2019, we had $267.8 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.

During the fourth quarter of 2019, we repurchased a principal amount of $32.2 million of our outstanding Senior Convertible Notes, for an aggregate cost of $23.0 million. As a result of these repurchases, we recognized a pre-tax gain of $2.7 million, which was net of the unamortized debt discount write-offs of $6.2 million and the unamortized deferred financing costs write-offs of $0.3 million, and is reflected in gain on extinguishment of debt in our Consolidated Statements of Operations for the year ended December 31, 2019.

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, 2019, 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, 2019.

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.

Subsequent to December 31, 2019, we repurchased a principal amount of $27.9 million of our outstanding Notes, for an aggregate cost of $22.2 million, including accrued interest, which will be reflected in our Consolidated Financial Statements subsequent to the year ended December 31, 2019.

Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2019:

	Payments due by period				
Contractual obligations	**Total**	**Within 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
			(In thousands)		
Senior unsecured notes[1]	$ 1,982,568	$ —	$ 962,815	$ 619,753	$ 400,000
Interest payments on senior unsecured notes[1]	450,676	122,288	209,442	81,446	37,500
Borrowings under Oasis Credit Facility[1]	337,000	—	—	337,000	—
Borrowings under OMP Credit Facility[1]	458,500	—	458,500	—	—
Interest payments on borrowings under Oasis Credit Facility[1]	365	365	—	—	—
Interest payments on borrowings under OMP Credit Facility[1]	508	508	—	—	—
Asset retirement obligations[2]	56,784	1,909	1,987	175	52,713
Finance leases[3]	7,908	3,009	3,909	351	639
Operating leases[3]	60,791	20,217	11,476	10,019	19,079
Volume commitment agreements[4]	594,537	82,515	202,078	169,662	140,282
Total contractual cash obligations	$ 3,949,637	$ 230,811	$ 1,850,207	$ 1,218,406	$ 650,213

(1) See Note 13 to our consolidated financial statements for a description of our senior unsecured notes, Revolving Credit Facilities and related interest payments. As of December 31, 2019, we had $337.0 million of borrowings and $15.1 million of outstanding letters of credit issued under the Oasis Credit Facility and $458.5 million of borrowings and $1.7 million of outstanding letters of credit issued 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 14 to our consolidated financial statements.

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

(4) See Note 22 to our consolidated financial statements for a description of our 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 gas properties

Crude 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.

The provision for DD&A of oil and 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 crude 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 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.

Crude oil and natural gas reserve quantities and standardized measure of future net revenue

Our independent reserve engineers and technical staff prepare our estimates of crude 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 crude 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. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude 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, crude 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 crude 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

We apply the Accounting Standards Codification Topic 606 (“ASC 606”) using the modified retrospective method. We apply ASC 606 to all new contracts entered into after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of December 31, 2017. ASC 606 includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. 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.

Crude oil, natural gas and NGL 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 crude oil and natural gas production is sold to purchasers under short-term (less than twelve-month) contracts at market-based prices, and our NGL production is sold to purchasers under long-term (more than twelve-month) contracts at market-based prices. The sales prices for crude oil, natural gas and NGLs 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 crude oil, natural gas and NGL, 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 crude oil and natural gas sales are derived from the sales of crude oil and natural gas purchased from third parties. 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 crude oil or natural 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 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 gas properties by field and compare such undiscounted future cash flows to the carrying amount of the oil and gas properties in the applicable field to determine if the carrying amount is recoverable. The factors used to determine the undiscounted future cash flows are subject to our judgment and expertise and include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates and estimates of operating and development costs. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and 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, our estimated undiscounted future cash flows 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 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.

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 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 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 our 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 ratably over the requisite service period, which is generally the vesting period. The fair value of restricted stock grants is based on the closing sales price of our common stock on the date of grant or, if applicable, the date of modification. 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 probabilistic assessment (see Note 16 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 PSUs granted are accounted for when they occur.

OMP Phantom Unit Awards

We recognize compensation expense for phantom unit awards based on OMP common units (collectively, the "OMP Phantom Unit Awards," and each an "OMP Phantom Unit") granted to our 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 OMP Phantom Unit Awards granted 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

See Note 2 to our consolidated financial statements for a description of the effect of recent accounting pronouncements on our consolidated financial statements.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2019, 2018 and 2017. Although the impact of inflation has been 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 crude oil and natural gas prices increased drilling activity in our areas of operations.

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 22 to our consolidated financial statements for a description of our commitments and contingencies.

Non-GAAP Financial Measures

E&P Cash G&A, Cash MT&G, 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 financial measures should not be considered in isolation or as a substitute for general and administrative expenses, marketing, transportation and gathering expense, 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 E&P Cash G&A, Cash MT&G, 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.

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 and other non-cash charges 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,		
	2019	2018	2017
		(In thousands)	
General and administrative expenses	$ 118,701	$ 102,482	$ 77,560
Equity-based compensation expenses	(32,251)	(27,910)	(25,436)
Litigation contingency expenses[1]	(20,000)	—	—
E&P Cash G&A	**$ 66,450**	**$ 74,572**	**$ 52,124**

(1) In 2019, we incurred a charge to establish a loss accrual of $20.0 million, which we believe is the estimable amount of loss that could potentially be incurred from our pending legal proceedings based upon currently available information.

Cash MT&G

We define Cash MT&G as the total marketing, transportation and gathering expenses less non-cash valuation charges on pipeline imbalances. Cash MT&G is not a measure of marketing, transportation and gathering expenses as determined by GAAP. Management believes that the presentation of Cash MT&G provides useful additional information to investors and analysts to assess the cash costs incurred to get its commodities to market without regard for the change in value of its pipeline imbalances, which vary monthly based on commodity prices.

The following table presents a reconciliation of the GAAP financial measure of marketing, transportation and gathering expenses to the non-GAAP financial measure of Cash MT&G for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Marketing, transportation and gathering expenses	$ 128,806	$ 107,193	$ 55,740
Pipeline imbalances	(2,446)	(4,331)	812
Cash MT&G	**$ 126,360**	**$ 102,862**	**$ 56,552**

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,		
	2019	2018	2017
		(In thousands)	
Interest expense	$ 176,223	$ 159,085	$ 146,837
Capitalized interest	11,964	17,226	12,797
Amortization of deferred financing costs	(8,832)	(7,590)	(6,907)
Amortization of debt discount	(12,164)	(11,120)	(10,080)
Cash Interest	**$ 167,191**	**$ 157,601**	**$ 142,647**

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 non-recurring 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 attributable to Oasis 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.

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,		
	2019	2018	2017
		(In thousands)	
Net income (loss) including non-controlling interests	$ (90,647)	$ (19,500)	$ 127,446
(Gain) loss on sale of properties	4,455	(28,587)	(1,774)
(Gain) loss on extinguishment of debt	(4,312)	13,848	—
Net (gain) loss on derivative instruments	106,314	(28,457)	71,657
Derivative settlements[(1)]	19,098	(213,528)	(8,264)
Interest expense, net of capitalized interest	176,223	159,085	146,837
Depreciation, depletion and amortization	787,192	636,296	530,802
Impairment	10,257	384,228	6,887
Rig termination	384	—	—
Exploration expenses	6,658	27,432	11,600
Equity-based compensation expenses	33,607	29,273	26,534
Income tax benefit	(32,715)	(5,843)	(203,304)
Litigation contingency expenses[(2)]	20,000	—	—
Other non-cash adjustments	3,035	4,435	(745)
Adjusted EBITDA	**1,039,549**	**958,682**	**707,676**
Adjusted EBITDA attributable to non-controlling interests	51,525	21,703	3,904
Adjusted EBITDA attributable to Oasis	988,024	936,979	703,772
Cash Interest	(167,191)	(157,601)	(142,647)
Capital expenditures[(3)]	(843,368)	(2,203,453)	(836,204)
Capitalized interest	11,964	17,226	12,797
Free Cash Flow	**$ (10,571)**	**$ (1,406,849)**	**$ (262,282)**
Net cash provided by operating activities	$ 892,853	$ 996,421	$ 507,876
Derivative settlements[(1)]	19,098	(213,528)	(8,264)
Interest expense, net of capitalized interest	176,223	159,085	146,837
Rig termination	384	—	—
Exploration expenses	6,658	27,432	11,600
Deferred financing costs amortization and other	(27,263)	(29,057)	(18,311)
Current tax expense	(16)	23	(421)
Changes in working capital	(51,423)	13,871	69,104
Litigation contingency expenses[(2)]	20,000	—	—
Other non-cash adjustments	3,035	4,435	(745)
Adjusted EBITDA	**1,039,549**	**958,682**	**707,676**
Adjusted EBITDA attributable to non-controlling interests	51,525	21,703	3,904
Adjusted EBITDA attributable to Oasis	988,024	936,979	703,772
Cash Interest	(167,191)	(157,601)	(142,647)
Capital expenditures[(3)]	(843,368)	(2,203,453)	(836,204)
Capitalized interest	11,964	17,226	12,797
Free Cash Flow	**$ (10,571)**	**$ (1,406,849)**	**$ (262,282)**

(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) In 2019, we incurred a charge to establish a loss accrual of $20.0 million, which we believe is the estimable amount of loss that could potentially be incurred from our pending legal proceedings based upon currently available information.

(3) 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 statements of cash flows are presented on a cash basis. Acquisitions totaled $21.0 million, $951.9 million and $54.0 million for the years ended December 31, 2019, 2018 and 2017, respectively. In addition, capital expenditures (including acquisitions) reflected in the table above 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,		
	2019	2018	2017
		(In thousands)	
Loss before income taxes including non-controlling interests	$ (332,069)	$ (167,292)	$ (179,129)
(Gain) loss on sale of properties	4,455	(38,188)	(1,774)
(Gain) loss on extinguishment of debt	(4,312)	13,848	—
Net (gain) loss on derivative instruments	106,314	(28,457)	71,657
Derivative settlements(1)	19,098	(213,528)	(8,264)
Interest expense, net of capitalized interest	159,287	156,742	146,818
Depreciation, depletion and amortization	766,959	618,402	519,853
Impairment	5,856	384,228	6,887
Exploration expenses	6,658	27,432	11,600
Rig termination	384	—	—
Equity-based compensation expenses	32,251	27,910	25,436
Litigation contingency expenses(2)	20,000	—	—
Other non-cash adjustments	2,446	4,331	(812)
Adjusted EBITDA	**$ 787,327**	**$ 785,428**	**$ 592,272**

(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) In 2019, we incurred a charge to establish a loss accrual of $20.0 million, which we believe is the estimable amount of loss that could potentially be incurred from our pending legal proceedings based upon currently available information.

Midstream

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Income before income taxes including non-controlling interests	$ 224,096	$ 141,001	$ 102,340
Loss on sale of properties	—	9,622	—
Interest expense, net of capitalized interest	16,936	2,343	19
Depreciation, depletion and amortization	37,152	29,282	15,999
Equity-based compensation expenses	1,744	1,547	1,461
Adjusted EBITDA	**$ 279,928**	**$ 183,795**	**$ 119,819**

Well Services

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Income (loss) before income taxes including non-controlling interests	$ (1,866)	$ 31,023	$ 15,091
Depreciation, depletion and amortization	13,631	15,698	12,939
Impairment	4,401	—	—
Equity-based compensation expenses	1,397	1,588	1,264
Other non-cash adjustments	589	104	67
Adjusted EBITDA	**$ 18,152**	**$ 48,413**	**$ 29,361**

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) per share 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.

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,		
	2019	2018	2017
	(In thousands, except per share data)		
Net income (loss) attributable to Oasis	$ (128,243)	$ (35,296)	$ 123,796
Tax reform rate change adjustments	—	—	(171,900)
(Gain) loss on sale of properties	4,455	(28,587)	(1,774)
(Gain) loss on extinguishment of debt	(4,312)	13,848	—
Net (gain) loss on derivative instruments	106,314	(28,457)	71,657
Derivative settlements(1)	19,098	(213,528)	(8,264)
Impairment	10,257	384,228	6,887
Rig termination	384	—	—
Amortization of deferred financing costs	8,832	7,591	6,907
Amortization of debt discount	12,164	11,120	10,080
Litigation contingency expenses(2)	20,000	—	—
Other non-cash adjustments	3,035	4,435	(745)
Tax impact(3)	(42,782)	(35,759)	(31,696)
Adjusted Net Income Attributable to Oasis	**$ 9,202**	**$ 79,595**	**$ 4,948**
Diluted earnings (loss) attributable to Oasis per share	$ (0.41)	$ (0.11)	$ 0.52
Tax reform rate change adjustments	—	—	(0.72)
(Gain) loss on sale of properties	0.01	(0.09)	(0.01)
(Gain) loss on extinguishment of debt	(0.01)	0.04	—
Net (gain) loss on derivative instruments	0.34	(0.09)	0.30
Derivative settlements(1)	0.06	(0.69)	(0.03)
Impairment	0.03	1.24	0.03
Rig termination	—	—	—
Amortization of deferred financing costs	0.03	0.02	0.03
Amortization of debt discount	0.04	0.04	0.04
Litigation contingency expenses(2)	0.06	—	—
Other non-cash adjustments	0.01	0.01	—
Tax impact(3)	(0.13)	(0.11)	(0.14)
Adjusted Diluted Earnings Attributable to Oasis Per Share	**$ 0.03**	**$ 0.26**	**$ 0.02**
Diluted weighted average shares outstanding(4)	315,324	310,860	237,875
Effective tax rate applicable to adjustment items	23.7 %	23.7 %	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) In 2019, we incurred a charge to establish a loss accrual of $20.0 million, which we believe is the estimable amount of loss that could potentially be incurred from our pending legal proceedings based upon currently available information.
(3) 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.
(4) We included 322,000, 3,379,000 and 2,889,000 unvested stock awards for the years ended December 31, 2019, 2018 and 2017, respectively, in computing Adjusted Diluted Earnings Attributable to Oasis Per Share due to the dilutive effect under the treasury stock method.

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, NGL and crude 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 crude oil, natural gas and NGLs fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative 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 crude oil and natural gas prices. Our crude oil contracts will settle monthly based on the average NYMEX WTI. Our natural gas contracts will settle monthly based on the average NYMEX Henry Hub natural gas index price ("NYMEX HH").

As of December 31, 2019, we utilized fixed price swaps and two-way and three-way costless collars to reduce the volatility of crude oil prices on a significant portion of our future expected crude oil 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 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.

The following is a summary of our outstanding commodity derivative instruments as of December 31, 2019:

						Weighted Average Prices				
Commodity	**Settlement Period**	**Derivative Instrument**	**Index**	**Volumes**		**Fixed Price Swaps**	**Sub-Floor**	**Floor**	**Ceiling**	**Fair Value Assets (Liabilities)**
										(In thousands)
Crude oil	2020	Fixed price swaps	NYMEX WTI	6,550,000	Bbl	$ 57.17				$ (14,087)
Crude oil	2020	Two-way collar	NYMEX WTI	3,296,000	Bbl			$ 51.76	$ 61.76	(4,743)
Crude oil	2020	Three-way collar	NYMEX WTI	5,339,000	Bbl		$ 40.00	$ 52.79	$ 64.06	(330)
Crude oil	2021	Fixed price swaps	NYMEX WTI	248,000	Bbl	$ 56.05				36
Crude oil	2021	Two-way collar	NYMEX WTI	248,000	Bbl			$ 50.75	$ 59.13	(86)
Crude oil	2021	Three-way collar	NYMEX WTI	889,000	Bbl		$ 40.00	$ 51.04	$ 63.61	569
										$ (18,641)

A 10% increase in crude oil prices would decrease the fair value of our derivative position by approximately $71.4 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $62.6 million.

Interest rate risk. At December 31, 2019, we had (i) $71.8 million of senior unsecured notes at a fixed cash interest rate of 6.50% per annum, (ii) $1,242.9 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum, (iii) $267.8 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, 2019, we had $337.0 million of borrowings and $15.1 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, 2019, 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, 2019, we had $458.5 million of borrowings and $1.7 million of outstanding letters of credit 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, 2019, the outstanding borrowings under the OMP Credit Facility bore interest at LIBOR plus a 2.00% 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.

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, 2019, we recorded $0.2 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 crude 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 crude 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 crude oil and natural gas sales receivables owed to us. Historically, our credit losses on crude oil and natural gas sales receivables have been immaterial.

In addition, our crude 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 $1.2 million and a net derivative liability position of $19.8 million at December 31, 2019.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures

As required by Rule 13a-15(b) of the Exchange Act, management, under the supervision and with the participation of our Chief Executive Officer (“CEO”), our principal executive officer, and our Chief Financial Officer (“CFO”), our principal financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2019. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including our CEO and CFO as appropriate, to allow timely decisions regarding required disclosure. Based on the evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2019 at the reasonable assurance level.

Management’s report on internal control over financial reporting

Management, including our CEO and CFO, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles.

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

As of December 31, 2019, management assessed the effectiveness of our internal control over financial reporting. In making this assessment, management, including our CEO and CFO, used the criteria set forth by the *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based on this assessment, our CEO and CFO have concluded that our internal control over financial reporting was effective as of December 31, 2019.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this annual report on Form 10-K, has also audited the effectiveness of our internal control over financial reporting as of December 31, 2019 and has issued an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2019. Please see their “Report of Independent Registered Public Accounting Firm” included in Item 8 – Financial Statements and Supplementary Data.

Changes in internal control over financial reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

Item 8. Financial Statements and Supplementary Data

Index to Financial Statements

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, 2019 and 2018, and the related consolidated statements of operations, of changes in stockholders' equity and of cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's report on internal control over financial reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Oil and Natural Gas Reserves on Proved Oil and Natural Gas Properties, Net

As described in Notes 2 and 9 to the consolidated financial statements, the Company's consolidated proved oil and natural gas properties, net balance was $5.1 billion as of December 31, 2019. Depreciation, depletion and amortization (DD&A) expense for the year ended December 31, 2019 was $787.2 million. For the year ended December 31, 2019, the Company did not record impairment of proved oil and natural gas properties. Oil and natural gas exploration and development activities are accounted for using the successful efforts 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. The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of its carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and gas properties by field and compares such undiscounted future cash flows to the carrying amount of the oil and gas properties in the applicable field to determine if the carrying amount is recoverable. As disclosed by management, the factors used to determine the undiscounted future cash flows are subject to management's judgment and expertise and include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates and estimates of operating and development costs. 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. The estimates of oil and natural gas reserves have been developed by specialists, specifically petroleum engineers.

The principal considerations for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on proved oil and natural gas properties, net is a critical audit matter are there was significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating the significant assumptions used in developing those estimates, including future production, future price differentials, and future development costs.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and natural gas reserves, the calculation of DD&A expense and the impairment assessment of proved oil and natural gas properties. These procedures also included, among others, evaluating the significant assumptions used by management in developing these estimates, including future production, future price differentials and future development costs. Procedures were also performed to test the unit-of-production rate used to calculate DD&A expense and to test the identification of triggering events. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved oil and natural gas reserves. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of the data used by the specialists and an evaluation of the specialists' findings. Evaluating the significant assumptions relating to the estimates of proved oil and natural gas reserves also involved obtaining evidence to support the reasonableness of the assumptions, including whether the assumptions used were reasonable considering the past and current performance of the Company, and whether they were consistent with evidence obtained in other areas of the audit.

/s/PricewaterhouseCoopers LLP
Houston, Texas
February 26, 2020

We have served as the Company's auditor since 2007.

Oasis Petroleum Inc.
Consolidated Balance Sheets

	December 31, 2019	December 31, 2018
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 20,019	$ 22,190
Accounts receivable, net	371,181	387,602
Inventory	35,259	33,128
Prepaid expenses	10,011	10,997
Derivative instruments	535	99,930
Intangible assets, net	—	125
Other current assets	346	183
Total current assets	437,351	554,155
Property, plant and equipment		
Oil and gas properties (successful efforts method)	9,463,038	8,912,189
Other property and equipment	1,279,653	1,151,772
Less: accumulated depreciation, depletion, amortization and impairment	(3,764,915)	(3,036,852)
Total property, plant and equipment, net	6,977,776	7,027,109
Assets held for sale, net	21,628	—
Derivative instruments	639	6,945
Long-term inventory	13,924	12,260
Operating right-of-use assets	18,497	—
Other assets	29,438	25,673
Total assets	$ 7,499,253	$ 7,626,142
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 17,948	$ 20,166
Revenues and production taxes payable	233,090	216,695
Accrued liabilities	281,079	331,651
Accrued interest payable	37,388	38,040
Derivative instruments	19,695	84
Advances from joint interest partners	4,598	5,140
Current operating lease liabilities	6,182	—
Other current liabilities	2,903	—
Total current liabilities	602,883	611,776
Long-term debt	2,711,573	2,735,276
Deferred income taxes	267,357	300,055
Asset retirement obligations	56,305	52,384
Derivative instruments	120	20
Operating lease liabilities	17,915	—
Other liabilities	6,019	7,751
Total liabilities	3,662,172	3,707,262
Commitments and contingencies (Note 22)		
Stockholders' equity		

Common stock, $0.01 par value: 900,000,000 shares authorized; 324,198,057 shares issued and 321,231,319 shares outstanding at December 31, 2019 and 320,469,049 shares issued and 318,377,161 shares outstanding at December 31, 2018	3,189	3,157
Treasury stock, at cost: 2,966,738 and 2,091,888 shares at December 31, 2019 and December 31, 2018, respectively	(33,881)	(29,025)
Additional paid-in capital	3,112,384	3,077,755
Retained earnings	554,446	682,689
Oasis share of stockholders’ equity	3,636,138	3,734,576
Non-controlling interests	200,943	184,304
Total stockholders’ equity	3,837,081	3,918,880
Total liabilities and stockholders’ equity	$ 7,499,253	$ 7,626,142

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

Oasis Petroleum Inc.
Consolidated Statements of Operations

	Year Ended December 31,		
	2019	2018	2017
	(In thousands, except per share data)		
Revenues			
Oil and gas revenues	$ 1,408,771	$ 1,590,024	$ 1,034,634
Purchased oil and gas sales	408,791	550,344	133,542
Midstream revenues	212,208	120,504	72,752
Well services revenues	41,974	61,075	52,791
Total revenues	2,071,744	2,321,947	1,293,719
Operating expenses			
Lease operating expenses	223,384	193,912	177,134
Midstream expenses	62,146	32,758	17,589
Well services expenses	28,761	41,200	37,228
Marketing, transportation and gathering expenses	128,806	107,193	55,740
Purchased oil and gas expenses	409,180	553,461	134,615
Production taxes	112,592	133,696	88,133
Depreciation, depletion and amortization	787,192	636,296	530,802
Exploration expenses	6,658	27,432	11,600
Rig termination	384	—	—
Impairment	10,257	384,228	6,887
General and administrative expenses	143,506	121,346	91,797
Total operating expenses	1,912,866	2,231,522	1,151,525
Gain (loss) on sale of properties	(4,455)	28,587	1,774
Operating income	154,423	119,012	143,968
Other income (expense)			
Net gain (loss) on derivative instruments	(106,314)	28,457	(71,657)
Interest expense, net of capitalized interest	(176,223)	(159,085)	(146,837)
Gain (loss) on extinguishment of debt	4,312	(13,848)	—
Other income (expense)	440	121	(1,332)
Total other expense, net	(277,785)	(144,355)	(219,826)
Loss before income taxes	(123,362)	(25,343)	(75,858)
Income tax benefit	32,715	5,843	203,304
Net income (loss) including non-controlling interests	(90,647)	(19,500)	127,446
Less: Net income attributable to non-controlling interests	37,596	15,796	3,650
Net income (loss) attributable to Oasis	$ (128,243)	$ (35,296)	$ 123,796
Earnings (loss) attributable to Oasis per share:			
Basic (Note 18)	$ (0.41)	$ (0.11)	$ 0.53
Diluted (Note 18)	(0.41)	(0.11)	0.52
Weighted average shares outstanding:			
Basic (Note 18)	315,002	307,480	234,986
Diluted (Note 18)	315,002	307,480	237,875

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

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, 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 15)	—	—	—	—	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
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)
Treasury stock - tax withholdings	(760)	—	760	(6,846)	—	—	—	(6,846)
Other	—	—	—	—	(881)	—	(125)	(1,006)
Net income (loss)	—	—	—	—	—	(35,296)	15,796	(19,500)
Balance as of December 31, 2018	318,377	3,157	2,092	(29,025)	3,077,755	682,689	184,304	3,918,880
Equity-based compensation	3,729	32	—	—	34,982	—	378	35,392
Distributions to non-controlling interest owners	—	—	—	—	—	—	(21,270)	(21,270)
Treasury stock - tax withholdings	(875)	—	875	(4,856)	—	—	—	(4,856)
Other	—	—	—	—	(353)	—	(65)	(418)
Net income (loss)	—	—	—	—	—	(128,243)	37,596	(90,647)
Balance as of December 31, 2019	321,231	$ 3,189	2,967	$ (33,881)	$ 3,112,384	$ 554,446	$ 200,943	$ 3,837,081

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

Oasis Petroleum Inc.
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Cash flows from operating activities:			
Net income (loss) including non-controlling interests	$ (90,647)	$ (19,500)	$ 127,446
Adjustments to reconcile net income (loss) including non-controlling interests to net cash provided by operating activities:			
Depreciation, depletion and amortization	787,192	636,296	530,802
(Gain) loss on extinguishment of debt	(4,312)	13,848	—
(Gain) loss on sale of properties	4,455	(28,587)	(1,774)
Impairment	10,257	384,228	6,887
Deferred income taxes	(32,699)	(5,866)	(202,884)
Derivative instruments	106,314	(28,457)	71,657
Equity-based compensation expenses	33,607	29,273	26,534
Deferred financing costs amortization and other	27,263	29,057	18,311
Working capital and other changes:			
Change in accounts receivable, net	13,729	(23,508)	(166,386)
Change in inventory	(5,893)	(14,346)	(2,501)
Change in prepaid expenses	325	(2,354)	(838)
Change in accounts payable, interest payable and accrued liabilities	53,051	26,116	123,107
Change in other assets and liabilities, net	(9,789)	221	(22,485)
Net cash provided by operating activities	892,853	996,421	507,876
Cash flows from investing activities:			
Capital expenditures	(869,221)	(1,148,961)	(647,349)
Acquisitions	(21,009)	(581,650)	(61,874)
Proceeds from sale of properties	42,376	333,229	5,774
Costs related to sale of properties	—	(2,850)	(366)
Derivative settlements	19,098	(213,528)	(8,264)
Other	—	224	(2,681)
Net cash used in investing activities	(828,756)	(1,613,536)	(714,760)
Cash flows from financing activities:			
Proceeds from Revolving Credit Facilities	1,982,000	3,224,000	1,162,000
Principal payments on Revolving Credit Facilities	(1,972,500)	(2,586,000)	(1,377,000)
Repurchase of senior unsecured notes	(45,790)	(423,340)	—
Proceeds from issuance of senior unsecured notes	—	400,000	—
Deferred financing costs	(1,052)	(13,862)	(2,714)
Proceeds from sale of common stock, net of offering costs	—	—	302,191
Proceeds from sale of Oasis Midstream common units, net of offering costs	—	44,503	134,185
Purchases of treasury stock	(4,856)	(6,846)	(6,229)
Distributions to non-controlling interests	(21,270)	(14,114)	—
Payments on finance lease liabilities	(2,382)	—	—
Other	(418)	(1,756)	(55)
Net cash provided by (used in) financing activities	(66,268)	622,585	212,378
Increase (decrease) in cash and cash equivalents	(2,171)	5,470	5,494

Cash and cash equivalents:			
Beginning of period	22,190	16,720	11,226
End of period	$ 20,019	$ 22,190	$ 16,720
Supplemental cash flow information:			
Cash paid for interest, net of capitalized interest	$ 155,833	$ 141,196	$ 129,463
Cash paid for income taxes	111	38	12
Cash received for income tax refunds	146	25	281
Supplemental non-cash transactions:			
Change in accrued capital expenditures	$ (82,414)	$ 68,946	$ 83,508
Change in asset retirement obligations	4,917	3,880	(789)
Installment notes from acquisition	—	—	4,875
Issuance of shares in connection with acquisition	—	371,220	—

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

Oasis Petroleum Inc.
Notes to Consolidated Financial Statements

1. Organization and Operations of the Company

Oasis Petroleum Inc. (together with its consolidated subsidiaries, "Oasis" or the "Company") was originally formed in 2007 and was incorporated pursuant to the laws of the State of Delaware in 2010. The Company is an independent exploration and production company focused on the acquisition and development of onshore, unconventional crude oil and natural gas resources in the United States. Oasis Petroleum North America LLC ("OPNA") and Oasis Petroleum Permian LLC ("OP Permian") conduct the Company's exploration and production activities and own its oil and gas properties located in the North Dakota and Montana regions of the Williston Basin and the Texas region of the Delaware Basin, respectively. In addition to its exploration and production segment, the Company also operates a midstream business segment through Oasis Midstream Partners LP ("OMP") and Oasis Midstream Services LLC ("OMS") and a well services business segment through Oasis Well Services LLC ("OWS"), both of which are separate reportable business segments that are complementary to the Company's primary development and production activities. OMP is a growth-oriented, fee-based master limited partnership that develops and operates a diversified portfolio of midstream assets. The Company owns a substantial majority of the general partner and a majority of the outstanding units of OMP. In March 2020, the Company intends to transition its well fracturing services from OWS to a third-party provider who will provide services to the Company under a long-term agreement (see Note 12—Assets Held for Sale).

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements of the Company include the accounts of Oasis, the accounts of its wholly owned subsidiaries and the accounts of OMP and its general partner, OMP GP LLC ("OMP GP"). The Company has determined that the partners with equity at risk in OMP lack the authority, through voting rights or similar rights, to direct the activities that most significantly impact OMP's economic performance. Therefore, as the limited partners of OMP do not have substantive kick-out or substantive participating rights over OMP GP, OMP is a variable interest entity. Through the Company's ownership interest in OMP GP, the Company has the authority to direct the activities that most significantly affect economic performance and the right to receive benefits that could be potentially significant to OMP. Therefore, the Company is considered the primary beneficiary and consolidates OMP and records a non-controlling interest for the interest owned by the public. All intercompany balances and transactions have been eliminated upon consolidation. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Certain reclassifications of prior year balances have been made to conform such amounts to current year classifications. These reclassifications have no impact on net income.

Use of Estimates

Preparation of the Company's consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved crude oil and natural gas reserves and related cash flow estimates used in impairment tests of long-lived assets, estimates of future development, dismantlement and abandonment costs, estimates relating to certain crude oil and natural gas revenues and expenses and estimates of expenses related to legal, environmental and other contingencies. Certain of these estimates require assumptions regarding future commodity prices, future costs and expenses and future production rates. Actual results could differ from those estimates.

Estimates of crude oil and natural gas reserves and their values, future production rates and future costs and expenses are inherently uncertain for numerous reasons, including many factors beyond the Company's control. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, prevailing commodity prices, operating costs and other factors. These revisions may be material and could materially affect future depreciation, depletion and amortization ("DD&A") expense, dismantlement and abandonment costs, and impairment expense.

Risks and Uncertainties

As a crude oil and natural gas producer, the Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for crude oil and natural gas, which are dependent upon numerous factors beyond its control such as economic, political and regulatory developments and competition from other energy sources. The energy markets have historically been very volatile and there can be no assurance that crude oil and natural gas prices will not be subject to wide fluctuations in the future. As a result of current commodity prices, the Company plans to decrease its 2020 capital expenditures, excluding acquisitions, as compared to 2019, while continuing to concentrate its drilling activities in its core acreage, including in the Bakken and Three Forks formations in the Williston Basin and the Bone Spring and Wolfcamp formations in the Delaware Basin.

A substantial or extended decline in prices for crude oil and, to a lesser extent, natural gas, could have a material adverse effect on the Company’s financial position, results of operations, cash flows and quantities of crude oil and natural gas reserves that may be economically produced.

Cash Equivalents

The Company invests in certain money market funds, commercial paper and time deposits, all of which are stated at fair value or cost which approximates fair value due to the short-term maturity of these investments. The Company classifies all such investments with original maturity dates less than 90 days as cash equivalents.

Accounts Receivable

Accounts receivable are carried at cost on a gross basis, with no discounting, which approximates fair value due to their short-term maturities. The Company’s accounts receivable consist mainly of receivables from crude oil and natural gas purchasers and joint interest owners on properties the Company operates.

The Company regularly assesses the recoverability of all material trade and other receivables to determine their collectability. The Company accrues a reserve on a receivable when, based on management’s judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, the Company’s crude oil and natural gas receivables are collected within two months, and to date, the Company has had minimal bad debts. At December 31, 2019 and 2018, the Company had an allowance for doubtful accounts of $1.3 million and $1.5 million, respectively.

Inventory

Crude oil inventory includes crude oil in tanks and linefill. Linefill that represents the minimum volume of product in a pipeline system that enables the system to operate is generally not available to be withdrawn from the pipeline system until the expiration of the transportation contract. Crude oil in tanks and linefill in third party pipelines that is expected to be withdrawn within one year is included in inventory on the Company’s Consolidated Balance Sheets, and crude oil linefill in third party pipelines that is not expected to be withdrawn within one year is included in long-term inventory on the Company’s Consolidated Balance Sheets (see Note 5—Inventory).

Equipment and materials consist primarily of proppant, chemicals, tubular goods, well equipment to be used in future drilling or repair operations, well fracturing equipment and spare parts and equipment for the Company’s midstream assets. Equipment and materials are included in inventory on the Company’s Consolidated Balance Sheets (see Note 5—Inventory).

Inventory, including long-term inventory, is stated at the lower of cost and net realizable value with cost determined on an average cost method. The Company assesses the carrying value of inventory and uses estimates and judgment when making any adjustments necessary to reduce the carrying value to net realizable value. Among the uncertainties that impact the Company’s estimates are the applicable quality and location differentials to include in the Company’s net realizable value analysis. Additionally, the Company estimates the upcoming liquidation timing of the inventory. Changes in assumptions made as to the timing of a sale can materially impact net realizable value.

Joint Interest Partner Advances

The Company participates in the drilling of crude oil and natural gas wells with other working interest partners. Due to the capital intensive nature of crude oil and natural gas drilling activities, the working interest partner responsible for conducting the drilling operations may request advance payments from other working interest partners for their share of the costs. The Company expects such advances to be applied by working interest partners against joint interest billings for its share of drilling operations within 90 days from when the advance is paid. Advances to joint interest partners are included in other current assets on the Company’s Consolidated Balance Sheets.

Property, Plant and Equipment

Proved Oil and Gas Properties

Crude 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.

The provision for DD&A of oil and 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 crude 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 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.

The Company reviews its proved oil and gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of its carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and gas properties by field and compares such undiscounted future cash flows to the carrying amount of the oil and gas properties in the applicable field to determine if the carrying amount is recoverable. The factors used to determine the undiscounted future cash flows are subject to management’s judgment and expertise and include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates and estimates of operating and development costs. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value are subject to management’s 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, the Company’s estimated undiscounted future cash flows 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, the Company cannot predict when or if future impairment charges for proved oil and gas properties will be recorded.

Unproved Oil and Gas Properties

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 the Company specifically identifies leases that will revert to the lessor, at which time the Company expenses the associated lease acquisition costs. The expensing of the lease acquisition costs is recorded as impairment in the 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.

The Company assesses its unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage. The Company considers the following factors in its assessment of the impairment of unproved properties:

- the remaining amount of unexpired term under its leases;
- its ability to actively manage and prioritize its capital expenditures to drill leases and to make payments to extend leases that may be close to expiration;
- its ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- its ability to convey partial mineral ownership to other companies in exchange for their drilling of leases; and
- its evaluation of the continuing successful results from the application of completion technology in the Bakken and Three Forks formations in the Williston Basin and Bone Springs and Wolfcamp formations in the Delaware Basin by the Company or by other operators in areas adjacent to or near the Company’s unproved properties.

For sales of entire working interests in unproved properties, a 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.

Capitalized Interest

The Company capitalizes a portion of its interest expense incurred on its outstanding debt. The amount capitalized is determined by multiplying the capitalization rate by the average amount of eligible accumulated capital expenditures and is limited to actual interest costs incurred during the period. The accumulated capital expenditures included in the capitalized interest calculation begin when the first costs are incurred and end when the asset is either placed into production or written off. The Company capitalized $12.0 million, $17.2 million and $12.8 million of interest costs for the years ended December 31, 2019, 2018 and 2017, respectively. These amounts are amortized over the life of the related assets.

Other Property and Equipment

The Company's produced and flowback water disposal facilities, natural gas processing plants, pipelines, buildings, furniture, software, equipment and leasehold improvements are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets. The Company uses estimated lives of 30 years for its produced and flowback water disposal facilities, natural gas processing plants and pipelines, 20 years for its buildings, two to seven years for its furniture, software and equipment and the remaining lease term for its leasehold improvements. The calculation for the straight-line DD&A method for its produced and flowback water disposal facilities takes into consideration estimated future dismantlement, restoration and abandonment costs, which are net of estimated salvage values. The cost of assets disposed of and the associated accumulated DD&A are removed from the Company's Consolidated Balance Sheets with any gain or loss realized upon the sale or disposal included in the Company's Consolidated Statements of Operations.

Exploration Expenses

Exploration costs, including certain geological and geophysical expenses and the costs of carrying and retaining undeveloped acreage, are charged to expense as incurred.

Costs from drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful. Determination is usually made on or shortly after drilling or completing the well, however, in certain situations a determination cannot be made when drilling is completed. The Company defers capitalized exploratory drilling costs for wells that have found a sufficient quantity of producible hydrocarbons but cannot be classified as proved because they are located in areas that require major capital expenditures or governmental or other regulatory approvals before production can begin. These costs continue to be deferred as wells-in-progress as long as development is underway, is firmly planned for in the near future or the necessary approvals are actively being sought.

Net changes in capitalized exploratory well costs are reflected in the following table for the periods presented:

	December 31, 2019	2018	2017
	(In thousands)		
Beginning of period	$ 4,457	$ —	$ 2,097
Exploratory well cost additions (pending determination of proved reserves)	—	26,497	10
Exploratory well cost reclassifications (successful determination of proved reserves)	(4,222)	(22,040)	(571)
Exploratory well dry hole costs (unsuccessful in adding proved reserves)	(235)	—	(1,536)
End of period	$ —	$ 4,457	$ —

As of December 31, 2019, the Company had no exploratory well costs that were capitalized for a period of greater than one year after the completion of drilling.

Business Combinations

The Company accounts for business combinations under the acquisition method of accounting. Accordingly, the Company recognizes 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.

The Company makes 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 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, the Company reviews comparable purchases and sales of oil and gas properties within the same regions and uses 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.

Assets Held for Sale

The Company occasionally markets non-core oil and gas properties and other property and equipment. At the end of each reporting period, the Company evaluates the properties being marketed to determine whether any should be reclassified as held-for-sale. The held-for-sale criteria include: management commits to a plan to sell; the asset is available for immediate sale; an active program to locate a buyer exists; the sale of the asset is probable and expected to be completed within one year; the asset is being actively marketed for sale; and it is unlikely that significant changes to the plan will be made. If each of these criteria is met, the property is reclassified as held-for-sale on the Company’s Consolidated Balance Sheets and measured at the lower of their carrying amount or estimated fair value less costs to sell. Fair values are estimated using accepted valuation techniques, such as a discounted cash flow model, valuations performed by third parties, earnings multiples, indicative bids or indicative market pricing, when available. Management considers historical experience and all available information at the time the estimates are made; however, the fair value that is ultimately realized upon the sale of the assets to be divested may differ from the estimated fair values reflected in the consolidated financial statements. DD&A expense is not recorded on assets to be divested once they are classified as held for sale.

Deferred Financing Costs

The Company capitalizes costs incurred in connection with obtaining financing. These costs are amortized over the term of the related financing using the straight-line method, which approximates the effective interest method. The amortization expense is recorded as a component of interest expense in the Company’s Consolidated Statements of Operations. The deferred financing costs related to the Company’s senior unsecured notes as well as the Revolving Credit Facilities are included in long-term debt and other assets, respectively, on the Company’s Consolidated Balance Sheets.

Asset Retirement Obligations

In accordance with the Financial Accounting Standard Board’s (“FASB”) authoritative guidance on asset retirement obligations (“ARO”), the Company records 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 ARO represents the estimated amount the Company 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 using the unit-of-production method. The accretion expense is recorded as a component of depreciation, depletion and amortization in the Company’s Consolidated Statements of Operations.

Some of the Company’s midstream assets, including certain pipelines and the 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. The Company is not able to reasonably estimate the fair value of the asset retirement obligations for these assets because the settlement dates are indeterminable given the expected continued use of the assets with proper maintenance. The Company will record asset retirement obligations for these assets in the periods in which the settlement dates are reasonably determinable.

The Company determines the ARO by calculating the present value of estimated 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. These assumptions represent Level 3 inputs, as further discussed in Note 7 — Fair Value Measurements. 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.

Revenue Recognition

In the first quarter of 2018, the Company 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 Company applies ASC 606 to all new contracts entered into after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of December 31, 2017. ASC 606 includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. Enhanced disclosures in accordance with ASC 606 have been provided in Note 4—Revenue Recognition.

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.

Crude oil, natural gas and natural gas liquids (“NGL”) revenues from the Company’s interests in producing wells are recognized when it satisfies a performance obligation by transferring control of a product to a customer. Substantially all of the Company’s crude oil and natural gas production is sold to purchasers under short-term (less than twelve-month) contracts at market-based prices, and the Company’s NGL production is sold to purchasers under long-term (more than twelve-month) contracts at market-based prices. The sales prices for crude oil, natural gas and NGLs 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 crude oil, natural gas and NGLs, the Company sells the majority of its production soon after it is produced at various locations. As a result, the Company maintains a minimum amount of product inventory in storage.

The Company’s purchased crude oil and natural gas sales are derived from the sale of crude oil and natural gas purchased from third parties. Revenues and expenses from these sales and purchases are generally recorded on a gross basis, as the Company acts as a principal in these transactions by assuming control of the purchased crude oil or natural gas before it is transferred to the customer. In certain cases, the Company enters 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 ASC 845.

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. 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 the Company’s Consolidated Statements of Operations. Midstream revenues are earned through fee-based arrangements, under which the Company receives 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 the Company takes control of the product prior to sale and is the principal in the transaction, and therefore, recognizes revenues and expenses on a gross basis.

Revenues and Production Taxes Payable

The Company calculates and pays taxes and royalties on crude oil and natural gas in accordance with the particular contractual provisions of the lease, license or concession agreements and the laws and regulations applicable to those agreements.

Leases

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, *Leases (Topic 842)*, which requires lessees to recognize a right-of-use (“ROU”) asset and related liability on the balance sheet for leases with durations greater than twelve months and also requires certain quantitative and qualitative disclosures about leasing arrangements. 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*; Accounting Standards Update No. 2018-11, *Targeted Improvements;* and Accounting Standards Update No. 2019-01, *Leases (Topic 842): Codification Improvements*.

The Company adopted the new standard as of January 1, 2019 using the required modified retrospective approach and elected 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. Prior period amounts were not adjusted.

ASU 2018-01 provides a number of optional practical expedients in transition. The Company elected the package of practical expedients under the transition guidance within the new standard, including the practical expedient to not reassess under the new standard any prior conclusions about lease identification, lease classification and initial direct costs; the use-of hindsight practical expedient; the practical expedient to not reassess the prior accounting treatment for existing or expired land easements; and the practical expedient pertaining to combining lease and non-lease components for all asset classes. In addition, the Company elected not to apply the recognition requirements of ASC 842 to leases with terms of one year or less, and as such, recognition of lease payments for short-term leases are recognized in net income on a straight line basis. See Note 20—Leases for the adoption impact and disclosures required by ASC 842.

Concentrations of Market and Credit Risk

The future results of the Company's crude oil and natural gas operations will be affected by the market prices of crude oil and natural gas. The availability of a ready market for crude oil and natural gas products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of crude oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of crude oil, natural gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty. The current global oversupply of crude oil has caused a sharp decline in crude oil prices since mid-2014, though recently crude oil prices have been improving. A substantial or extended decline in the price of crude oil could have a material adverse effect on the Company's financial position, cash flows and results of operations.

The Company operates in the exploration, development and production sector of the crude oil and gas industry. The Company's receivables include amounts due from purchasers of its crude oil and natural gas production and amounts due from joint interest partners for their respective portions of operating expenses and exploration and development costs. While certain of these customers and joint interest partners are affected by periodic downturns in the economy in general or in their specific segment of the crude oil or natural gas industry, including the current period of low commodity prices, the Company believes that its level of credit-related losses due to such economic fluctuations has been and will continue to be immaterial to the Company's results of operations over the long-term. In addition, a portion of the Company's trade receivables are collateralized.

The Company manages and controls market and counterparty credit risk. In the normal course of business, collateral is not required for financial instruments with credit risk. Financial instruments which potentially subject the Company to credit risk consist principally of temporary cash balances and derivative financial instruments. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments. The Company attempts to limit the amount of credit exposure to any one financial institution or company. The Company believes the credit quality of its customers is generally high. In the normal course of business, letters of credit or parent guarantees are required for counterparties which management perceives to have a higher credit risk.

Risk Management

The Company utilizes derivative financial instruments to manage risks related to changes in crude oil and natural gas prices. As of December 31, 2019, the Company utilized fixed price swaps and two-way and three-way costless collar options to reduce the volatility of crude oil prices on a significant portion of its future expected crude oil production (see Note 8—Derivative Instruments).

The Company records all derivative instruments on the Consolidated Balance Sheets as either assets or liabilities measured at their estimated fair value. 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. The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. Gains and losses from valuation changes in commodity derivative instruments are reported in the other income (expense) section of the Company's Consolidated Statements of Operations. The Company's 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 the Company's 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. Cash settlements are reflected as investing activities in the Company's Consolidated Statements of Cash Flows.

Derivative financial instruments that hedge the price of crude oil and natural gas are executed with major financial institutions that expose the Company to market and credit risks and which may, at times, be concentrated with certain counterparties or groups of counterparties. At December 31, 2019, the Company has derivatives in place with nine counterparties. Although notional amounts are used to express the volume of these contracts, the amounts potentially subject to credit risk in the event of nonperformance by the counterparties are substantially smaller. The credit worthiness of the counterparties is subject to continual review. The Company believes the risk of nonperformance by its counterparties is low. Full performance is anticipated, and the Company has no past-due receivables from its counterparties. The Company's policy is to execute financial derivatives only with major, credit-worthy financial institutions.

The Company's derivative contracts are documented with industry standard contracts known as a Schedule to the Master Agreement and International Swaps and Derivatives Association, Inc. Master Agreement ("ISDA"). Typical terms for the ISDAs include credit support requirements, cross default provisions, termination events and set-off provisions. The Company is not required to provide any credit support to its counterparties other than cross collateralization with the properties securing the Revolving Credit Facilities (see Note 13 — Long-Term Debt). The Company has limitations under the Revolving Credit Facilities, including a provision limiting the total amount of production that may be hedged by the Company to certain percentages of forecasted and current production amounts. As of December 31, 2019, the Company was in compliance with these limitations.

Contingencies

Certain conditions may exist as of the date the Company's consolidated financial statements are issued that may result in a loss to the Company, but which will only be resolved when one or more future events occur or fail to occur. The Company's management, with input from legal counsel, assesses such contingent liabilities, and such assessment inherently involves judgment. In assessing loss contingencies related to legal proceedings that are pending against the Company or unasserted claims that may result in proceedings, the Company's management, with input from legal counsel, evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a loss has been incurred and the amount of liability can be estimated, then the estimated undiscounted liability is accrued in the Company's consolidated financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, is disclosed. Actual results could vary from these estimates and judgments.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 22—Commitments and Contingencies for additional information regarding the Company's contingencies.

Environmental Costs

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and which do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

Equity-Based Compensation

Restricted Stock Awards

The Company has granted restricted stock awards to its employees and directors under its Amended and Restated 2010 Long Term Incentive Plan, the majority of which vest over a three-year period. The fair value of restricted stock grants is based on the closing sales price of the Company's common stock on the date of grant or, if applicable, the date of modification. Compensation expense is recognized ratably over the requisite service period. Equity-based compensation expense recorded for restricted stock awards is included in general and administrative expenses on the Company's Consolidated Statements of Operations. Forfeitures associated with restricted stock awards granted are accounted for when they occur.

Performance Share Units

The Company recognizes compensation expense for its performance share units ("PSUs") granted to its officers under its Amended and Restated 2010 Long Term Incentive Plan. 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 probabilistic assessment (see Note 16—Equity-Based Compensation for a description of the inputs used in this model). Equity-based compensation expense recorded for the PSUs is included in general and administrative expenses on the Company's Consolidated Statements of Operations. Forfeitures associated with PSUs granted are accounted for when they occur.

OMP Phantom Unit Awards

The Company has granted phantom unit awards based on OMP common units (collectively, the "OMP Phantom Unit Awards," and each an "OMP Phantom Unit") to its employees under its Amended and Restated 2010 Long Term Incentive Plan and OMP GP has granted OMP Phantom Unit Awards to employees of the Company under the Oasis Midstream Partners LP 2017 Long Term Incentive Plan ("OMP LTIP"). The OMP Phantom Unit Awards are accounted for as liability-classified awards since the awards will settle in cash, and equity-based compensation cost is accounted for under the fair value method in accordance with GAAP. The OMP Phantom Unit Awards generally vest in equal installments each year over a three-year period, and compensation expense will be recognized over the requisite service period. Compensation expense 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 OMP Phantom Unit Awards granted are accounted for when they occur.

Associated Excess Tax Benefits

Any excess tax benefit arising from the Company's equity-based compensation plan is recognized as a credit to income tax expense or benefit in the Company's Consolidated Statements of Operations.

Treasury Stock

Treasury stock shares represent shares withheld by the Company equivalent to the payroll tax withholding obligations due from employees upon the vesting of restricted stock awards. The Company includes the withheld shares as treasury stock on its Consolidated Balance Sheets and separately pays the payroll tax obligation. These retained shares are not part of a publicly announced program to repurchase shares of the Company's common stock and are accounted for at cost. The Company does not have a publicly announced program to repurchase shares of its common stock.

Income Taxes

The Company's provision for taxes includes both federal and state taxes. The Company records its 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.

The Company applies significant judgment in evaluating its tax positions and estimating its 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 the Company's estimates, which could impact its financial position, results of operations and cash flows.

The Company also accounts 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 the Company 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. The Company did not have any uncertain tax positions outstanding and, as such, did not record a liability for the years ended December 31, 2019 and 2018. All deferred tax assets and liabilities, along with any related valuation allowance, are classified as noncurrent on the Company's Consolidated Balance Sheets.

Recent Accounting Pronouncements

Fair Value Measurement

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. The Company does not expect the adoption of this guidance to have an impact on its financial position, cash flows or results of operations, but it may result in changes to disclosures.

Financial Instruments - Credit Losses

In June 2016, the FASB issued Accounting Standards Update No. 2016-13, *Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments* ("ASU 2016-13"), which replaces the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information, including forecasts, to develop credit loss estimates. ASU 2016-13 requires entities to use the new methodology to measure impairment of financial instruments, including trade and joint interest billing receivables, and may result in earlier recognition of credit losses than under current GAAP. ASU 2016-13 is effective for fiscal years beginning after December 15, 2019. Although the Company continues to evaluate ASU 2016-13, based on our current credit portfolio the Company does not expect the adoption of this standard to have a material impact on its financial position, cash flows or results of operations, but it may result in changes to disclosures.

Income Taxes

In December 2019, the FASB issued Accounting Standards Update No. 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes* ("ASU 2019-12"), which simplifies the accounting for income taxes by removing certain exceptions to the general principles and also simplification of areas such as separate entity financial statements and interim recognition of enactment of tax laws or rate changes. ASU 2019-12 is effective for fiscal years beginning after December 15, 2020, including interim reporting periods within those years. The Company is currently evaluating the effect of ASU 2019-12, but does not expect the adoption of this guidance to have a material impact on its financial position, cash flows or result of operations.

3. Oasis Midstream Partners

Oasis Midstream Partners LP

OMP is a growth-oriented, fee-based master limited partnership formed by the Company to own, develop, operate and acquire a diversified portfolio of midstream assets in North America that are integral to the crude oil and natural gas operations of Oasis and are strategically positioned to capture volumes from other producers.

In 2017, OMP completed its initial public offering ("IPO") of common units representing limited partner interests, and the OMP common units are traded on The Nasdaq Stock Market LLC under the symbol OMP. In exchange for contributed assets, Oasis received 5,125,000 common units and 13,750,000 subordinated units, representing a 68.6% limited partner interest in OMP and the right to receive cash distributions from OMP. In addition to and concurrent with the closing of the IPO, OMP GP retained a non-economic general partnership interest and was issued incentive distribution rights in OMP.

Contractual arrangements

The Company entered into several long-term, fee-based contractual arrangements with OMP for midstream services, including (i) natural gas gathering, compression, processing and gas lift services; (ii) crude oil 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, the Company provides substantial labor and overhead support for OMP. Upon completion of the OMP IPO, the Company entered into a 15-year services and secondment agreement with OMP pursuant to which the Company provides all personnel, equipment, electricity, chemicals and services (including third-party services) required for OMP to operate such assets, and OMP reimburses the Company for its share of the actual costs of operating such assets. In addition, pursuant to the services and secondment agreement, the Company performs 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. The Company has also seconded to OMP certain of its employees to operate, construct, manage and maintain its assets, and OMP reimburses the Company for direct general and administrative expenses incurred by the Company 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.

Oasis Midstream Partners LP 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 $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 LLC ("Bobcat DevCo") and Beartooth DevCo LLC ("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 ("OMP Operating"), 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. The effective date of the OMP Dropdown was July 1, 2018, and the OMP Dropdown closed on November 19, 2018. The OMP Dropdown did not have a material impact on the Company's consolidated financial statements. After the OMP Dropdown, OMS owned 75% of the non-controlling interests of Bobcat DevCo and 30% of the non-controlling interests of Beartooth DevCo.

2019 Capital Expenditures Arrangement

On February 22, 2019, the Company entered into a memorandum of understanding (the "MOU") with OMP regarding the funding of Bobcat DevCo's expansion capital expenditures for the 2019 calendar year (the "2019 Capital Expenditures Arrangement"). Pursuant to the MOU, in exchange for increasing its percentage ownership interest in Bobcat DevCo, OMP agreed to make up to $80.0 million of the capital contributions to Bobcat DevCo that OMS would otherwise have been required to contribute. During the year ended December 31, 2019, OMP made capital contributions to Bobcat DevCo pursuant to the 2019 Capital Expenditures Arrangement of $73.0 million. As a result, OMS's ownership interest in Bobcat DevCo decreased from 75% as of December 31, 2018 to 64.7% as of December 31, 2019. The 2019 Capital Expenditures Arrangement ended on December 31, 2019.

Assignment of midstream assets in Delaware Basin

Effective November 1, 2019, the Company assigned to Panther DevCo LLC ("Panther DevCo"), an indirect, wholly-owned subsidiary of OMP, certain crude oil gathering and produced water gathering and disposal assets (the "Delaware Midstream Assets") under development to support the Company's production in the Delaware Basin. OMP agreed to reimburse the Company for all capital expenditures previously made with respect to the Delaware Midstream Assets, which were approximately $24.9 million. OMP funded this amount with borrowings under its revolving credit facility. Also, effective November 1, 2019, Panther DevCo entered into long-term commercial agreements with the Company, including a Crude Oil Gathering Agreement and a Produced Water Gathering and Disposal Agreement (collectively, the "Delaware Basin Commercial Agreements"), for crude oil and produced water midstream services in the Delaware Basin, which generally contain terms similar to those contained in the existing commercial agreements between OMP and the Company for midstream services in the Williston Basin. The Delaware Basin Commercial Agreements additionally provide the Company with certain purchase rights with respect to the Delaware Midstream Assets, and provide Panther DevCo with certain sale rights with respect to the Delaware Midstream Assets, in the event of a change of control of OMP or Panther DevCo, which purchase and sale rights will expire after two years.

4. Revenue Recognition

Exploration and production revenues

The Company's exploration and production revenues are derived from contracts for crude oil, natural gas and natural gas liquids ("NGL") sales, as described below. Generally, for the majority of these contracts: (i) each unit (barrel ("bbl"), mcf, gallon, etc.) of commodity product is a separate performance obligation, as the Company's promise is to sell multiple distinct units of commodity product at a point in time; (ii) the transaction price principally consists of variable consideration, which amount is determinable each month end based on the Company's right to invoice at month end for the value of commodity product sold to the customer that month; and (iii) the transaction price is allocated to each performance obligation based on the commodity product's standalone selling price and recognized as revenue upon delivery of the commodity product, which is the point in time when the customer obtains control of the commodity product and the Company's performance obligation is satisfied. The sales of crude oil, natural gas and NGLs as presented on the Company's Consolidated Statements of Operations represent the Company's share of revenues net of royalties and excluding revenue interests owned by others. When selling crude oil, natural gas and NGLs on behalf of royalty owners or working interest owners, the Company is acting as an agent and thus reports the revenue on a net basis. To the extent actual volumes and prices of crude oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded. The Company's contracts with customers typically require payments for crude oil, natural gas and NGL sales within 30 days following the calendar month of delivery.

Crude oil revenues. The Company sells a substantial majority of its crude oil through bulk sales at delivery points on crude oil gathering systems to a variety of customers under short-term contracts that include a specified quantity of crude oil to be delivered and sold to the customer at a specified delivery point. The customer pays a market-based transaction price, which incorporates differentials that include, but are not limited to, transportation costs.

Natural gas and NGL revenues. The Company's natural gas sales consist of unprocessed gas sales and residue gas sales. Unprocessed gas is sold at delivery points at or near the wellhead under various contracts, in which the customer pays a transaction price based on its sale of the bifurcated NGLs and residue gas, less any associated fees. Revenue is recorded on a net basis, with processing fees deducted within revenue rather than as a separate expense line item, as title and control transfer at the delivery point. Residue gas from the Company's gas processing plants located in Wild Basin is sold at the tailgate or transported and sold at other downstream sales points, and the customer pays a transaction price based on a market indexed per-unit rate for the quantities sold. NGLs from the Company's gas processing plants located in Wild Basin are sold at the tailgate or trucked and sold at other downstream locations, and the customer pays a transaction price based on a market indexed per-unit rate for the quantities sold.

Purchased crude oil and natural gas sales. The Company's purchased crude oil and natural gas sales are derived from the sale of crude oil and natural gas purchased from a third party. The Company sells the purchased commodities to a variety of customers under short-term contracts that include specified quantities of crude oil and natural gas to be sold and delivered to the customer at a specified delivery point. The customer pays a market-based transaction price, which is based on the price index applicable for the location of the sale. Revenues and expenses from these sales and purchases are generally recorded on a gross basis, as the Company acts as a principal in these transactions by assuming control of the purchased crude oil or natural gas before it is transferred to the customer. In certain cases, the Company enters 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 ASC 845.

Prior period performance obligations. For sales of commodities, the Company records revenue in the month production is delivered to the purchaser. However, settlement statements and payment may not be received for 20 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between estimates and the actual amounts received for product sales once payment is received from the purchaser. Such differences have historically not been significant. The Company uses knowledge of its properties, its properties' historical performance, spot market prices and other factors as the basis for these estimates. For the year ended December 31, 2019 and 2018, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

Revenues associated with contracts with customers for crude oil, natural gas and NGL sales were as follows for the years ended December 31, 2019, 2018 and 2017:

Exploration and Production Revenues

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Crude oil revenues	$ 1,261,413	$ 1,425,409	$ 912,806
Purchased crude oil sales	401,554	540,633	132,331
Natural gas and NGL revenues	147,358	164,615	121,828
Purchased natural gas sales	7,207	6,078	1,211
Total exploration and production revenues	**$ 1,817,532**	**$ 2,136,735**	**$ 1,168,176**

Midstream revenues

The Company's midstream revenues are derived from its contracts with customers for midstream services and product sales under the following arrangements:

Fee-based arrangements. Under fee-based arrangements, the Company receives a fee for midstream services provided to its customers, and revenues are recognized using the output method for measuring the satisfaction of performance obligations. Revenues earned under fee-based arrangements are generally directly related to the volume of crude oil, natural gas and produced and flowback water that flows through the Company's systems, and the Company does not take ownership to the volumes it handles for its customers. Payments under fee-based arrangements are generally due 30 days after receipt of invoice. The Company generates revenues under fee-based arrangements as follows:

- *Crude oil and natural gas revenues*. The Company is party to certain contracts for crude oil gathering, stabilization, blending, storage and transportation, as well as natural gas gathering, compression, processing and gas lift services. Under these customer contracts, the Company provides daily integrated midstream services on a stand ready basis over a period of time, which represents a single performance obligation since the customer simultaneously receives and consumes the benefits of these services on a daily basis. Satisfaction of the Company's performance obligation is measured as each day of service is completed, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized based upon the transaction price at month-end under the right to invoice practical expedient.
- *Produced and flowback water revenues.* The Company is party to certain contracts with customers for produced and flowback water gathering and disposal services, under which it provides daily integrated midstream services on a stand ready basis over a period of time, which represents a single performance obligation since the customer simultaneously receives and consumes the benefits of these services on a daily basis. Satisfaction of the Company's performance obligation is measured as each day of service is completed, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized based upon the transaction price at month-end under the right to invoice practical expedient.

Purchase arrangements. Under purchase arrangements, revenues and expenses are recognized on a gross basis since the Company takes control of the product prior to sale and is the principal in the transaction. Revenues are recognized using the output method for measuring the satisfaction of performance obligations based upon the volume of natural gas, NGLs or freshwater delivered to customers. Payments under purchase arrangements are generally due 30 days after receipt of invoice. The Company generates revenues under purchase arrangements as follows:

- *Purchased crude oil sales.* The Company purchases and sells crude oil at various delivery points on crude oil gathering systems to a variety of customers under short-term contracts that include a specified quantity of crude oil to be sold and delivered to the customer at a specified delivery point. The Company purchases and sells the crude oil to different counterparties at market-based prices. Market-based pricing is based on the price index applicable for the location of the sale.
- *Natural gas and NGL revenues.* The Company is party to certain purchase arrangements with third parties pursuant to which the Company purchases natural gas from third parties at a connection point and obtains control prior to performing services and is the principal in the transaction. The Company gathers, compresses and/or processes the gas and then redelivers the residue gas and NGLs to different counterparties at market-based prices.
- *Freshwater revenues.* Under these customer contracts, the Company supplies and distributes freshwater to its customers for hydraulic fracturing and production optimization. These contracts contain multiple distinct performance obligations since each freshwater barrel can be sold separately and is not dependent nor highly interrelated with other barrels.

Prior period performance obligations. The Company records revenue for midstream services or product sales when the performance obligations under the terms of its customer contracts are satisfied. The Company measures the satisfaction of its performance obligations using the output method based upon the volume of crude oil, natural gas or water that flows through its systems. In certain cases, the Company is required to estimate these volumes during a reporting period and record any differences between the estimated volumes and actual volumes in the following reporting period. Such differences have historically not been significant. For the years ended December 31, 2019, 2018 and 2017, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

Revenues associated with contracts with customers for midstream services were as follows for the years ended December 31, 2019, 2018 and 2017:

Midstream Revenues(1)

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Midstream service revenues			
Crude oil and natural gas revenues	$ 95,399	$ 73,028	$ 37,369
Produced and flowback water revenues	40,534	37,791	30,727
Total midstream service revenues	$ 135,933	$ 110,819	$ 68,096
Midstream product revenues			
Purchased crude oil sales	$ 30	$ 3,633	$ —
Natural gas and NGL revenues	70,746	1,464	—
Freshwater revenues	5,529	8,221	4,656
Total midstream product revenues	$ 76,305	$ 13,318	$ 4,656
Total midstream revenues	**$ 212,238**	**$ 124,137**	**$ 72,752**

(1) Represents midstream revenues excluding all intercompany revenues for work performed by the midstream services business segment for the Company’s working interests that are eliminated in consolidation and are therefore not included in midstream services revenues.

Well services revenues

Hydraulic fracturing revenues. Hydraulic fracturing revenue is recognized upon the completion of each hydraulic fracturing of a well. These services are composed of various components, such as personnel, equipment and hydraulic fracturing materials, but management determined that each component is not distinct, as it cannot be used on its own or together with a resource readily available to the customer. Revenue is recognized when the performance obligations of hydraulic fracturing a well in its totality are completed; generally, this is over a period of time due to all work being performed for a customer occurring on the customer's property, where the customer has control over the work in process as it is being performed. In addition, the Company's assets being used to perform the obligations have no alternative use at the time of performance and the Company has the right to payment for performance to date. Payments from customers are generally received by the Company within one month after the month in which services are provided. In addition, revenue from product sales to third parties is generated when OPNA requests that third-party hydraulic fracturing companies hydraulic fracture OPNA's wells. Although the labor is provided by the third-party hydraulic fracturing company, the materials (e.g., sand, chemicals, etc.) used in the hydraulic fracturing of the wells are provided by OWS. The third-party hydraulic fracturing company or OPNA pays OWS for the materials delivered to the wells. Revenue is recognized once the performance obligations to transfer hydraulic fracturing materials are completed.

Equipment rental revenues. Equipment rental revenue is generated when OPNA or a third-party hydraulic fracturing company rents equipment from OWS. This equipment is used in the preparation stage of hydraulic fracturing services or after the hydraulic fracturing services have been completed. Equipment rental revenues are calculated based on the equipment's daily rental rate and the number of days that the equipment was rented by the customer. OWS's performance obligation is satisfied when the entire rental period is completed. Equipment rental revenues are recognized over a period of time due to the customer simultaneously receiving and consuming the benefits of the rental equipment provided by OWS on a daily basis. Satisfaction of the Company's performance obligation is measured at the completion of each day's rental period, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized at the time of invoicing for the entire rental period under the right to invoice practical expedient. Payments from customers are generally received by the Company within one month after the month in which services are provided.

Revenues associated with contracts with customers for hydraulic fracturing services and equipment rental sales were as follows for the years ended December 31, 2019, 2018 and 2017:

Well Services Revenues(1)

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Hydraulic fracturing revenues	$ 39,112	$ 56,620	$ 49,266
Equipment rental revenues	2,862	4,455	3,525
Total well services revenues	**$ 41,974**	**$ 61,075**	**$ 52,791**

(1) Represents well services revenues excluding all intercompany revenues for work performed by the well services business segment for the Company's working interests that are eliminated in consolidation and are therefore not included in well services revenues.

Contract balances

Contract balances are the result of timing differences between revenue recognition, billings and cash collections. Contract liabilities are recorded for consideration received from customers primarily related to (i) temporary deficiency quantities under minimum volume commitments which are recognized as revenue when the customer makes up the volumes or the deficiency makeup period expires and (ii) aid in construction payments received from customers which are recognized as revenue over the expected period of future benefit. The Company does not recognize contract assets or contract liabilities under its customer contracts for which invoicing occurs once the Company's performance obligations have been satisfied and payment is unconditional. Contract liabilities are classified as current or long-term based on the timing of when the Company expects to recognize revenue. As of December 31, 2018, there were no contract balances outstanding. The following table reflects the changes in the Company's contract liabilities during the year ended December 31, 2019:

	(In thousands)
Balance as of December 31, 2018	$ —
Cash received	2,174
Revenues recognized	(69)
Balance as of December 31, 2019	$ 2,105

Remaining performance obligations

ASC 606 requires presentation of information about partially and wholly unsatisfied performance obligations under contracts that exist as of the end of the period. The following table presents estimated revenue allocated to remaining performance obligations for contracted revenues that are unsatisfied (or partially satisfied) as of December 31, 2019:

	(In thousands)
2020	$ 18,452
2021	20,203
2022	19,244
2023	12,642
2024	11,870
Thereafter	2,768
Total	$ 85,179

The partially and wholly unsatisfied performance obligations presented in the table above are generally limited to customer contracts which have fixed pricing and fixed volume terms and conditions, which generally include customer contracts with minimum volume commitment payment obligations.

The Company has elected practical expedients, pursuant to ASC 606, to exclude from the presentation of remaining performance obligations: (i) contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct service that forms part of a series of distinct services and (ii) contracts with an original expected duration of one year or less.

5. Inventory

The following table sets forth the Company’s inventory:

	December 31,	
	2019	2018
	(In thousands)	
Inventory		
Crude oil inventory	$ 18,296	$ 14,933
Equipment and materials	16,963	18,195
Total inventory	$ 35,259	$ 33,128
Long-term inventory		
Linefill in third-party pipelines	$ 13,924	$ 12,260
Long-term inventory	$ 13,924	$ 12,260
Total	$ 49,183	$ 45,388

6. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

	December 31, 2019	December 31, 2018
	(In thousands)	
Accounts receivable, net		
Trade accounts	$ 276,629	$ 245,546
Joint interest accounts	82,112	133,375
Other accounts	13,699	10,207
Total	372,440	389,128
Allowance for doubtful accounts	(1,259)	(1,526)
Total accounts receivable, net	$ 371,181	$ 387,602
Revenues and production taxes payable		
Revenue suspense	$ 78,950	$ 75,685
Royalties payable	133,092	124,884
Production taxes payable	21,048	16,126
Total revenue and production taxes payable	$ 233,090	$ 216,695
Accrued liabilities		
Accrued capital costs	$ 128,592	$ 216,079
Accrued lease operating expenses	34,151	26,988
Accrued oil and gas purchases	51,087	32,713
Accrued general and administrative expenses	41,843	23,901
Accrued midstream and well services operating expenses	17,958	17,521
Other accrued liabilities	7,448	14,449
Total accrued liabilities	$ 281,079	$ 331,651

7. Fair Value Measurements

In accordance with the FASB's authoritative guidance on fair value measurements, the Company's financial assets and liabilities are measured at fair value on a recurring basis. The Company's financial instruments, including certain cash and cash equivalents, accounts receivable, accounts payable and other payables, are carried at cost, which approximates their respective fair market values due to their short-term maturities. The Company recognizes its non-financial assets and liabilities, such as ARO (see Note 14—Asset Retirement Obligations) and proved oil and gas properties upon impairment (see Note 9—Property, Plant and Equipment), at fair value on a non-recurring basis.

As defined in the authoritative guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable.

The authoritative guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities ("Level 1" measurements) and the lowest priority to unobservable inputs ("Level 3" measurements). The three levels of the fair value hierarchy are as follows:

Level 1 — Unadjusted quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Pricing inputs, other than unadjusted quoted prices in active markets included in Level 1, are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 — Pricing inputs are generally less observable from objective sources, requiring internally developed valuation methodologies that result in management's best estimate of fair value.

Financial Assets and Liabilities

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis:

	Fair value at December 31, 2019			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$ 146	$ —	$ —	$ 146
Commodity derivative instruments (see Note 8)	—	1,174	—	1,174
Total assets	$ 146	$ 1,174	$ —	$ 1,320
Liabilities:				
Commodity derivative instruments (see Note 8)	$ —	$ 19,815	$ —	$ 19,815
Total liabilities	$ —	$ 19,815	$ —	$ 19,815

	Fair value at December 31, 2018			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$ 143	$ —	$ —	$ 143
Commodity derivative instruments (see Note 8)	—	106,875	—	106,875
Total assets	$ 143	$ 106,875	$ —	$ 107,018
Liabilities:				
Commodity derivative instruments (see Note 8)	$ —	$ 104	$ —	$ 104
Total liabilities	$ —	$ 104	$ —	$ 104

The Level 1 instruments presented in the tables above consist of money market funds included in cash and cash equivalents on the Company's Consolidated Balance Sheets at December 31, 2019 and 2018. The Company's money market funds represent cash equivalents backed by the assets of high-quality major banks and financial institutions. The Company identifies the money market funds as Level 1 instruments because the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained, and there are active markets for the underlying investments.

The Level 2 instruments presented in the tables above consist of commodity derivative instruments, which include crude oil and natural gas swaps and collars. The fair values of the Company's commodity derivative instruments are based upon a third-party preparer's calculation using mark-to-market valuation reports provided by the Company's counterparties for monthly settlement purposes to determine the valuation of its derivative instruments. The Company has the third-party preparer evaluate other readily available market prices for its derivative contracts as there is an active market for these contracts. The third-party preparer performs its independent valuation using a moment matching method similar to Turnbull-Wakeman for Asian options. The significant inputs used are crude oil prices, volatility, skew, discount rate and the contract terms of the derivative instruments. However, the Company does not have access to the specific proprietary valuation models or inputs used by its counterparties or third-party preparer. The Company compares the third-party preparer's valuation to counterparty valuation statements, investigating any significant differences, and analyzes monthly valuation changes in relation to movements in crude oil and natural gas forward price curves. The determination of the fair value for derivative instruments also incorporates a credit adjustment for non-performance risk, as required by GAAP. The Company calculates the credit adjustment for derivatives in an asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a net liability position is based on the Company's market credit spread. Based on these calculations, the Company recorded an adjustment to reduce the fair value of its net derivative liability by $0.5 million at December 31, 2019 and an adjustment to reduce the fair value of its net derivative asset by $0.2 million at December 31, 2018.

There were no transfers between fair value levels during the years ended December 31, 2019 and 2018.

8. Derivative Instruments

The Company utilizes derivative financial instruments to manage risks related to changes in crude oil and natural gas prices. The Company's crude oil contracts will settle monthly based on the average NYMEX West Texas Intermediate crude oil index price ("NYMEX WTI"). The Company's natural gas contracts will settle monthly based on the average NYMEX Henry Hub natural gas index price ("NYMEX HH").

At December 31, 2019, the Company utilized fixed price swaps and two-way and three-way costless collars to reduce the volatility of crude oil prices on a significant portion of its future expected crude oil production. The Company's fixed price swaps are comprised of a sold call and a purchased put established at the same price (both ceiling and floor), which the Company will receive for the volumes under contract. 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) the Company 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) the Company will receive for the volumes under contract.

All derivative instruments are recorded on the Company's Consolidated Balance Sheets as either assets or liabilities measured at their fair value (see Note 7—Fair Value Measurements). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value are recognized in the other income (expense) section of the Company's Consolidated Statements of Operations as a net gain or loss on derivative instruments. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making a payment to or receiving a payment from the counterparty. These cash settlements represent the cumulative gains and losses on the Company's 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 the Company's Consolidated Statements of Cash Flows.

At December 31, 2019, the Company had the following outstanding commodity derivative instruments:

					Weighted Average Prices				
Commodity	Settlement Period	Derivative Instrument	Index	Volumes		Fixed Price Swaps	Sub-Floor	Floor	Ceiling	Fair Value Assets (Liabilities)
									(In thousands)
Crude oil	2020	Fixed price swaps	NYMEX WTI	6,550,000	Bbl	$ 57.17				$ (14,087)
Crude oil	2020	Two-way collar	NYMEX WTI	3,296,000	Bbl			$ 51.76	$ 61.76	(4,743)
Crude oil	2020	Three-way collar	NYMEX WTI	5,339,000	Bbl		$ 40.00	$ 52.79	$ 64.06	(330)
Crude oil	2021	Fixed price swaps	NYMEX WTI	248,000	Bbl	$ 56.05				36
Crude oil	2021	Two-way collar	NYMEX WTI	248,000	Bbl			$ 50.75	$ 59.13	(86)
Crude oil	2021	Three-way collar	NYMEX WTI	889,000	Bbl		$ 40.00	$ 51.04	$ 63.61	569
									$ (18,641)

Subsequent to December 31, 2019, the Company entered into additional swaps and two-way and three-way costless collars. As of February 26, 2020, the Company had the following outstanding commodity derivative contracts, which includes settlements from January 2020:

						Weighted Average Prices			
Commodity	Settlement Period	Derivative Instrument	Index	Volumes		Fixed Price Swaps	Sub-Floor	Floor	Ceiling
Crude oil	2020	Fixed price swaps	NYMEX WTI	6,948,000	Bbl	$ 57.14			
Crude oil	2020	Two-way collar	NYMEX WTI	3,296,000	Bbl			$ 51.99	$ 61.83
Crude oil	2020	Three-way collar	NYMEX WTI	6,098,000	Bbl		$ 40.74	$ 53.28	$ 63.88
Crude oil	2021	Fixed price swaps	NYMEX WTI	310,000	Bbl	$ 56.01			
Crude oil	2021	Two-way collar	NYMEX WTI	248,000	Bbl			$ 51.38	$ 59.33
Crude oil	2021	Three-way collar	NYMEX WTI	1,313,000	Bbl		$ 40.00	$ 50.79	$ 62.46

The following table summarizes the location and amounts of gains and losses from the Company's commodity derivative instruments recorded in the Company's Consolidated Statements of Operations for the periods presented:

	Year Ended December 31,		
Statement of Operations Location	2019	2018	2017
		(In thousands)	
Net gain (loss) on derivative instruments	$ (106,314)	$ 28,457	$ (71,657)

In accordance with the FASB's authoritative guidance on disclosures about offsetting assets and liabilities, the Company is required to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting agreement. The Company's derivative instruments are presented as assets and liabilities on a net basis by counterparty, as all counterparty contracts provide for net settlement. No margin or collateral balances are deposited with counterparties, and as such, gross amounts are offset to determine the net amounts presented in the Company's Consolidated Balance Sheets.

The following tables summarize the location and fair value of all outstanding commodity derivative instruments recorded in the Company's Consolidated Balance Sheets:

Commodity	Balance Sheet Location	December 31, 2019 Gross Recognized Assets/Liabilities	December 31, 2019 Gross Amount Offset	December 31, 2019 Net Recognized Fair Value Assets/Liabilities
			(In thousands)	
Derivatives assets:				
Commodity contracts	Derivative instruments — current assets	$ 633	$ (98)	$ 535
Commodity contracts	Derivative instruments — non-current assets	3,295	(2,656)	639
Total derivatives assets		$ 3,928	$ (2,754)	$ 1,174
Derivatives liabilities:				
Commodity contracts	Derivative instruments — current liabilities	$ 33,812	$ (14,117)	$ 19,695
Commodity contracts	Derivative instruments — non-current liabilities	686	(566)	120
Total derivatives liabilities		$ 34,498	$ (14,683)	$ 19,815

Commodity	Balance Sheet Location	December 31, 2018 Gross Recognized Assets/Liabilities	December 31, 2018 Gross Amount Offset	December 31, 2018 Net Recognized Fair Value Assets/Liabilities
			(In thousands)	
Derivatives assets:				
Commodity contracts	Derivative instruments — current assets	$ 110,729	$ (10,799)	$ 99,930
Commodity contracts	Derivative instruments — non-current assets	8,251	(1,306)	6,945
Total derivatives assets		$ 118,980	$ (12,105)	$ 106,875
Derivatives liabilities:				
Commodity contracts	Derivative instruments — current liabilities	$ 84	$ —	$ 84
Commodity contracts	Derivative instruments — non-current liabilities	20	—	20
Total derivatives liabilities		$ 104	$ —	$ 104

9. Property, Plant and Equipment

The following table sets forth the Company's property, plant and equipment:

	December 31, 2019	December 31, 2018
	(In thousands)	
Proved oil and gas properties[(1)]	$ 8,724,376	$ 7,878,104
Less: Accumulated depreciation, depletion, amortization and impairment	(3,601,019)	(2,853,353)
Proved oil and gas properties, net	5,123,357	5,024,751
Unproved oil and gas properties	738,662	1,034,085
Other property and equipment[(2)]	1,279,653	1,151,772
Less: Accumulated depreciation	(163,896)	(183,499)
Other property and equipment, net	1,115,757	968,273
Total property, plant and equipment, net	$ 6,977,776	$ 7,027,109

(1) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $42.3 million and $40.5 million at December 31, 2019 and 2018, respectively.
(2) Included in the Company's other property and equipment are estimates of future asset retirement costs of $1.4 million and $1.3 million at December 31, 2019 and 2018, respectively.

Impairment. The Company reviews its property, plant and equipment for impairment by asset group whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. If events occur that indicate an asset group may not be recoverable, the asset group is tested for recoverability. For its proved oil and gas properties, the Company estimates the expected undiscounted future cash flows of its proved oil and gas properties by field and then compares such amount to the carrying amount of the proved oil and 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, the Company will adjust the carrying amount of the proved oil and gas properties to fair value. The factors used to determine fair value are subject to management's 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. These assumptions represent Level 3 inputs, as further discussed under Note 7 — Fair Value Measurements.

The Company reports assets held for sale at the lower of their carrying amount or estimated fair value less costs to sell, with an impairment loss recognized to the extent the carrying amount exceeds this value. During the year ended December 31, 2019, the Company recorded an impairment loss of $4.4 million to adjust the carrying value of certain inventory and equipment held for sale to their estimated fair value (see Note 12—Assets Held for Sale). As of December 31, 2018, the Company sold certain proved and unproved oil and gas properties (see Note 11—Divestitures). For the year ended December 31, 2018, the Company recorded an impairment loss of $383.4 million, which was included in its exploration and production segment to adjust the carrying amount of these assets, net of the associated ARO liabilities, to their estimated fair value. For the years ended, December 31, 2019 and 2017, the Company did not record impairment of proved oil and gas properties.

In addition, as a result of expiring leases, periodic assessments and drilling plan uncertainty on certain acreage of unproved properties, the Company recorded non-cash impairment charges on its unproved oil and gas properties of $5.4 million, $0.9 million and $6.9 million for the years ended December 31, 2019, 2018 and 2017, respectively.

The Company reviews its other property and equipment for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred.

10. Acquisitions

Permian Basin Acquisition. On February 14, 2018, the Company and OP Permian, a wholly owned subsidiary of the Company, acquired from Forge Energy, LLC ("Forge Energy") approximately 22,000 net acres in the Delaware Basin (the "Permian Basin Acquisition") for aggregate consideration consisting of approximately $549.8 million in cash, inclusive of a $47.3 million deposit paid to Forge Energy in December 2017, and 46,000,000 shares of the Company's common stock (the "Purchase Price"), including customary post close adjustments. In connection with the closing of the Permian Basin Acquisition, the Company and Forge Energy entered into a Registration Rights Agreement that granted the equity holders of Forge Energy certain customary registration rights for the stock portion of the Purchase Price. The Company funded the cash portion of the Purchase Price with borrowings under a senior secured revolving line of credit among OPNA, as Borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "Oasis Credit Facility," and, together with the OMP Credit Facility, the "Revolving Credit Facilities"), and proceeds from the Company's December 2017 issuance of its common stock.

The Permian Basin Acquisition represents the Company's 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.

The Permian Basin Acquisition qualified as a business combination. As such, the Company estimated the fair value of the assets acquired and liabilities assumed as of the February 14, 2018 acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as further discussed under Note 7 — Fair Value Measurements. The Company recorded the assets acquired and liabilities assumed in the Permian Basin Acquisition at their estimated fair value of $921.0 million, which the Company considers to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized. The Permian Basin Acquisition is considered a taxable transaction; therefore, no deferred tax amounts were recognized at the acquisition date as the tax basis of the assets acquired and liabilities assumed were also recorded at fair value.

The following table summarizes the consideration paid for the Company’s acquisition and the fair value of the assets acquired and liabilities assumed as of the acquisition date.

	At February 14, 2018 (In thousands)
Consideration paid to Forge Energy:	
Cash	$ 549,770
Common stock: 46,000,000 shares issued	371,220
	$ 920,990
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed properties	$ 110,325
Proved undeveloped properties	166,552
Unproved lease acquisition costs	645,068
Inventory	293
Intangible assets	1,000
Asset retirement obligations	(2,248)
	$ 920,990

The results of operations for the Permian Basin Acquisition have been included in the Company’s consolidated financial statements since the February 14, 2018 closing date, including $71.7 million of total revenue and $15.6 million of operating income for the year ended December 31, 2018.

The Company also recorded a $1.0 million finite-lived intangible asset on the Company’s Consolidated Balance Sheets for a non-compete agreement with a one-year life. Intangible assets are amortized on a straight-line basis over the useful life, and the Company includes the amortization in depreciation, depletion and amortization expenses on the Company’s Consolidated Statements of Operations. For the years ended December 31, 2018 and 2019, amortization expense recognized for this non-compete agreement was approximately $0.9 million and $0.1 million, respectively.

Summarized below are the consolidated results of operations for the year ended December 31, 2018, on an unaudited pro forma basis, as if the acquisition and related financing had occurred on January 1, 2017. The unaudited pro forma financial information was derived from the historical consolidated statements of operations of the Company and the statement of revenues and direct operating expenses for the Permian Basin Acquisition properties, which were derived from the historical accounting records of Forge Energy. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the acquisition and related financing occurred on the basis assumed above, nor is such information indicative of the Company’s expected future results of operations.

	Year Ended December 31, 2018	Year Ended December 31, 2017
	(In thousands) Unaudited	
Revenues	$ 2,327,476	$ 1,337,468
Net income (loss) attributable to Oasis	(30,754)	159,838
Net income (loss) attributable to Oasis per share:		
Basic	$ (0.10)	$ 0.57
Diluted	(0.10)	0.56

Other Delaware Acquisition. On September 12, 2018, the Company completed the initial closing with undisclosed sellers to acquire certain exploration and production assets adjacent to the Company’s existing Delaware position (the “Other Delaware Acquisition”) for total cash consideration of $59.5 million. The final closing statement was finalized in January 2019, subsequent to the year ended December 31, 2018. Based on the FASB’s authoritative guidance, the acquisition qualified as a business combination, and as such, the Company estimated the fair value of the assets acquired as of the acquisition date. The Company recorded the oil and gas properties acquired at their estimated fair value of $59.5 million, which the Company considers to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized.

The results of operations for the Other Delaware Acquisition have been included in the Company's consolidated financial statements since the closing date. Pro forma information is not presented as the pro forma results would not be materially different from the information presented in the Company's Consolidated Statement of Operations.

Acquisitions. The Company actively reviews acquisition opportunities on an ongoing basis and acquires additional acreage and producing assets to supplement its existing operations. In addition to the Permian Basin Acquisition and Other Delaware Acquisition in 2018, the Company spent $21.0 million and $18.7 million to purchase certain acreage and producing assets through multiple transactions during the years ended December 31, 2019 and 2018, respectively. Based on the FASB's authoritative guidance, these transactions were considered asset acquisitions, and as such, the Company recorded the properties based on the fair value of the total cash consideration transferred on the acquisition dates.

11. Divestitures

The Company reviews portfolio opportunities on an ongoing basis and has engaged in various divestiture transactions over recent years.

Williston Non-Op Divestiture. On July 10, 2018, the Company completed the initial closing for the sale of certain non-operated oil and gas properties in the Williston Basin (the "Williston Non-Op Divestiture"). The transaction had an effective date of March 1, 2018, and the final closing statement was completed in the fourth quarter of 2018. The Company recognized a $18.1 million net gain on sale of properties, which includes customary post close adjustments, in its Consolidated Statements of Operations for the year ended December 31, 2018. During the year ended December 31, 2019, the Company recognized an additional $1.2 million net loss on sale of properties, which includes customary closing adjustments, in its Consolidated Statements of Operations. The divested properties were in the Company's exploration and production segment.

Foreman Butte Divestiture. On July 31, 2018, the Company completed the initial closing for the sale of oil and gas properties and certain other property and equipment primarily located in the Foreman Butte area of the Williston Basin (the "Foreman Butte Divestiture"). The transaction had an effective date of March 1, 2018, and the final closing statement was completed in January 2019. During the second quarter of 2018, the Company recorded an impairment loss of $383.4 million, which was included in impairment on the Company's Consolidated Statements of Operations, to adjust the carrying value of these assets to their estimated fair value, determined based on the expected sales price as negotiated with the purchaser, less costs to sell. The Company recognized a $10.7 million net loss on sale of properties, which includes customary post close adjustments, in its Consolidated Statements of Operations for the year ended December 31, 2018. During the year ended December 31, 2019, the Company recognized an additional $2.8 million net loss on sale of properties, which includes customary closing adjustments, in its Consolidated Statements of Operations. The Foreman Butte Divestiture consisted of oil and gas properties in the Company's exploration and production segment and included certain other property and equipment in the Company's midstream segment.

Other Williston Divestiture. On August 17, 2018, the Company completed the initial closing for the sale of additional non-strategic oil and gas properties in the Williston Basin (the "Other Williston Divestiture"). The transaction had an effective date of March 1, 2018, and the final closing statement was completed in March 2019. The Company recognized a $19.0 million net gain on sale of properties, which includes, and is subject to further, customary post close adjustments, in its Consolidated Statements of Operations for the year ended December 31, 2018. The divested properties were in the Company's exploration and production segment.

The Company determined that the Williston Non-Op Divestiture, Foreman Butte Divestiture and Other Williston Divestiture did not represent a strategic shift in its operations or have a significant impact on its financial position or results of operations; therefore, the Company did not account for these divestitures as discontinued operations.

In addition to the aforementioned divestitures, the Company also sold partial interests in certain oil and gas properties in the Company's exploration and production segment. During the year ended December 31, 2019, the Company recognized a $0.4 million net loss on sale of properties, which includes customary closing adjustments, in its Consolidated Statements of Operations.

Subsequent event. In January 2020, the Company completed the initial closing to sell certain oil and gas properties in the Williston Basin for total cash proceeds of $10.4 million. The transaction had an effective date of October 1, 2019, and the final closing statements for the transaction will be completed in July 2020. Upon the initial closing, the Company recognized a $10.4 million net gain on sale of properties, which includes customary closing adjustments, subsequent to the year ended December 31, 2019.

12. Assets Held for Sale

During the fourth quarter of 2019, the Company decided to pursue an exit from the well services business (the "Well Services Exit") and began an active program to locate buyers for certain well services inventory and equipment included within the Company's well services business segment. In March 2020, the Company intends to transition its well fracturing services from OWS to a third-party provider who will provide services to the Company under a long-term agreement. The assets expected to be sold related to the Well Services Exit met the criteria for assets held for sale and are classified as such as of December 31, 2019.

During the year ended December 31, 2019, the Company recorded an impairment loss of $4.4 million, which was included in impairment on the Company's Consolidated Statements of Operations, to adjust the carrying value of these assets to their estimated fair value less costs to sell, determined primarily based on indicative bids and indicative market pricing. The Company considered all available information at the time the estimates were made; however, the fair value that will be ultimately realized upon the sale of the assets to be divested may differ from the estimated fair values reflected in the consolidated financial statements. The expected sale of assets related to the Well Services Exit does not represent a strategic shift that will have a major effect on the Company's operations and financial results, and therefore, is not reported as discontinued operations.

The Company did not have any assets or liabilities classified as held for sale as of December 31, 2018. The following table presents balance sheet data related to the assets held for sale related to the Well Services Exit as of December 31, 2019:

	December 31, 2019
	(In thousands)
Inventory	$ 3,124
Other property and equipment	95,560
Less: Accumulated depreciation and impairment	(77,056)
Total assets held for sale, net	$ 21,628

13. Long-Term Debt

The Company's long-term debt consists of the following:

	December 31, 2019	December 31, 2018
	(In thousands)	
Oasis Credit Facility	$ 337,000	$ 468,000
OMP Credit Facility	458,500	318,000
Senior unsecured notes		
6.50% senior unsecured notes due November 1, 2021	71,835	71,835
6.875% senior unsecured notes due March 15, 2022	890,980	901,480
6.875% senior unsecured notes due January 15, 2023	351,953	366,094
6.25% senior unsecured notes due May 1, 2026	400,000	400,000
2.625% senior unsecured convertible notes due September 15, 2023	267,800	300,000
Total principal of senior unsecured notes	1,982,568	2,039,409
Less: unamortized deferred financing costs on senior unsecured notes	(15,618)	(20,865)
Less: unamortized debt discount on senior unsecured convertible notes	(50,877)	(69,268)
Total long-term debt	$ 2,711,573	$ 2,735,276

The carrying amount of the Company's long-term debt reported in the Consolidated Balance Sheets at December 31, 2019 is $2,711.6 million, which includes $1,982.6 million of senior unsecured notes, reductions for the unamortized debt discount related to the equity component of the senior unsecured convertible notes and the unamortized deferred financing costs on the senior unsecured notes of $50.9 million and $15.6 million, respectively, $337.0 million of borrowings under the Oasis Credit Facility and $458.5 million under the OMP Credit Facility. The Revolving Credit Facilities are recorded at values that approximate fair value since their variable interest rates are tied to current market rates. The fair value of the Company's senior unsecured notes, which are publicly traded and therefore categorized as Level 1 liabilities, was $1,812.6 million at December 31, 2019.

The Company has $71.8 million, $891.0 million, $619.8 million and $400.0 million of Notes maturing in 2021, 2022, 2023 and 2026, respectively, and indebtedness under the Oasis Credit Facility and the OMP Credit Facility that become due in 2023 and 2022, respectively. The Company does not have any other debt that matures within the five years ending December 31, 2024.

Senior secured revolving line of credit. The Company has the Oasis Credit Facility with an overall senior secured line of credit of $3,000.0 million as of December 31, 2019, which has a maturity date of the earlier of (i) October 16, 2023, (ii) 90 days prior to the maturity date of the Company's senior unsecured notes due in 2022 and 2023, of which $1,242.9 million is outstanding, to the extent such senior unsecured 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 the Company's senior unsecured convertible notes due in 2023, of which $267.8 million is outstanding, to the extent such senior unsecured convertible notes are not retired, converted, redeemed or refinanced to have a maturity date at least 90 days after October 16, 2023.

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. On April 15, 2019, the lenders under the Oasis Credit Facility completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2019, which reaffirmed the borrowing base and the aggregate elected commitment at $1,600.0 million and $1,350.0 million, respectively. In connection with the April 1, 2019 borrowing base redetermination, the Company entered into the First Amendment to the Third Amended and Restated Credit Agreement to the Oasis Credit Facility, dated April 15, 2019, which, among other things, incorporated the ability for the Company to request swingline loans subject to a swingline loans sublimit of $50.0 million.

On November 4, 2019, the lenders under the Oasis Credit Facility completed their regular semi-annual redetermination of the Company's borrowing base scheduled for October 1, 2019. As a result, the borrowing base decreased from $1,600.0 million to $1,300.0 million. The next redetermination of the Oasis Credit Facility's borrowing base is scheduled for April 1, 2020. Additionally, the Company entered into the third amendment to the Oasis Credit Facility, which among other things, decreased the aggregate elected commitment from $1,350.0 million to $1,100.0 million in conjunction with the redetermination.

Borrowings under the Oasis Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company's assets, including mortgage liens on oil and gas properties having at least 90% (as of December 31, 2019) of the reserve value as determined by reserve reports.

Borrowings under the Oasis Credit Facility are 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 London interbank offered rate ("LIBOR") loan or a domestic bank prime interest rate loan (defined in the Oasis Credit Facility as an Alternate Based Rate or "ABR" loan). As of December 31, 2019, any outstanding LIBOR and ABR loans would have borne their respective interest rates plus the applicable margin indicated in the following table:

Total Commitment Utilization Percentage	Applicable Margin for LIBOR Loans	Applicable Margin for ABR Loans
Less than 25%	1.50 %	0.00 %
Greater than or equal to 25% but less than 50%	1.75 %	0.25 %
Greater than or equal to 50% but less than 75%	2.00 %	0.50 %
Greater than or equal to 75% but less than 90%	2.25 %	0.75 %
Greater than or equal to 90%	2.50 %	1.00 %

A loan may be repaid at any time before the scheduled maturity of the Oasis Credit Facility upon the Company providing advance notification to the Lenders. Interest is paid quarterly on ABR loans based on the number of days an ABR loan is outstanding as of the last business day in March, June, September and December. The Company has the option to convert an ABR loan to a LIBOR-based loan upon providing advance notification to the Lenders. The minimum available loan term is one month and the maximum available loan term is six months for LIBOR-based loans (or twelve months with the consent of each leader). Interest for LIBOR loans is paid at the end of the applicable interest period for each loan or every three months for LIBOR loans that have loan terms greater than three months. At the end of a LIBOR loan term, the Oasis Credit Facility allows the Company to elect to repay the borrowing, continue a LIBOR loan with the same or differing loan term or convert the borrowing to an ABR loan.

On a quarterly basis, the Company also pays 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.

As of December 31, 2019, the Oasis Credit Facility contained covenants that included, 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 the assets of the Company and its 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 crude oil and natural gas derivative financial instruments;
- a requirement that the Company 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 the Company maintain a Current Ratio (as defined in the Oasis Credit Facility) of consolidated current assets (including unused borrowing 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"), the Company is 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, 2019, the Company had $337.0 million of borrowings and $15.1 million of outstanding letters of credit issued under the Oasis Credit Facility, resulting in an unused borrowing capacity of $747.9 million. As of December 31, 2018, the Company had $468.0 million of borrowings and $14.0 million of outstanding letters of credit issued under the Oasis Credit Facility, resulting in an unused borrowing capacity of $868.0 million. As of December 31, 2019 and 2018, the weighted average interest rate on borrowings under the Oasis Credit Facility was 3.5% and 4.2%, respectively. The Company was in compliance with the financial covenants of the Oasis Credit Facility as of December 31, 2019 and 2018.

OMP Operating LLC revolving line of credit. Through its ownership of OMP, the Company has access to the OMP Credit Facility, which is available to fund working capital and to finance acquisitions and other capital expenditures of OMP. On May 6, 2019, OMP entered into an amendment to the OMP Credit Facility to (i) increase the aggregate amount of commitments from $400.0 million to $475.0 million; (ii) provide for the ability to further increase commitments to $675.0 million; and (iii) add a new lender to the bank group. On August 16, 2019, OMP entered into the third amendment to the OMP Credit Facility to (i) increase the aggregate amount of commitments from $475.0 million to $575.0 million and (ii) provide for the ability to further increase commitments to $775.0 million. As of December 31, 2019, the OMP Credit Facility has an aggregate amount of commitments of $575.0 million and has a maturity date of September 25, 2022.

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, as the borrower under the OMP Credit Facility, are unconditionally guaranteed on a joint and several basis by OMP, Bighorn DevCo and Panther DevCo.

Borrowings under the OMP Credit Facility bear interest at a rate per annum 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 determined in accordance with the OMP Credit Agreement as follows:

Consolidated Total Leverage Ratio	Applicable Margin for Eurodollar Loans	Applicable Margin for ABR Loans	Commitment Fee Rate
Less than or equal to 3.00 to 1.00	1.75 %	0.75 %	0.375 %
Greater than 3.00 to 1.00 but less than or equal to 3.50 to 1.00	2.00 %	1.00 %	0.375 %
Greater than 3.50 to 1.00 but less than or equal to 4.00 to 1.00	2.25 %	1.25 %	0.500 %
Greater than 4.00 to 1.00 but less than or equal to 4.50 to 1.00	2.50 %	1.50 %	0.500 %
Greater than 4.50 to 1.00	2.75 %	1.75 %	0.500 %

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, 2019, the Company had $458.5 million of borrowings and $1.7 million of outstanding letters of credit issued under the OMP Credit Facility, resulting in an unused borrowing capacity of $114.8 million. As of December 31, 2018, the Company had $318.0 million of borrowings under the OMP Credit Facility, resulting in an unused borrowing capacity of $82.0 million. As of December 31, 2019 and 2018, the weighted average interest rate on borrowings under the OMP Credit Facility was 3.8% and 4.2%, respectively. OMP Operating was in compliance with the financial covenants of the OMP Credit Facility as of December 31, 2019.

Senior unsecured notes. At December 31, 2019, the Company had $1,714.8 million principal amount of senior unsecured notes outstanding with maturities ranging from November 2021 to May 2026 and coupons ranging from 6.25% to 6.875% (the “Senior Notes”). Prior to certain dates, the Company has 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.

During the fourth quarter of 2019, the Company repurchased an aggregate principal amount of $24.6 million of its outstanding Senior Notes, consisting of $10.5 million principal amount of the 6.875% senior unsecured notes due March 15, 2022 and $14.1 million principal amount of the 6.875% senior unsecured notes due January 15, 2023, for an aggregate cost of $22.8 million. As a result of these repurchases, the Company recognized a pre-tax gain of $1.6 million, which was net of unamortized deferred financing costs write-offs of $0.2 million, and is reflected in gain on extinguishment of debt in the Company’s Consolidated Statements of Operations for the year ended December 31, 2019.

The indentures governing the Senior Notes restrict the Company’s ability and the ability of certain of the Company’s 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 the Company’s 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 the Company will cease to be subject to such covenants. The Company was in compliance with the terms of the indentures for the Senior Notes as of December 31, 2019.

Senior unsecured convertible notes. At December 31, 2019, the Company had $267.8 million of 2.625% senior unsecured convertible notes due September 2023 (the “Senior Convertible Notes”). During the fourth quarter of 2019, the Company repurchased a principal amount of $32.2 million of its outstanding Senior Convertible Notes, for an aggregate cost of $23.0 million. As a result of these repurchases, the Company recognized a pre-tax gain of $2.7 million, which was net of the unamortized debt discount write-offs of $6.2 million and the unamortized deferred financing costs write-offs of $0.3 million, and is reflected in gain on extinguishment of debt in the Company’s Consolidated Statements of Operations for the year ended December 31, 2019.

The Company has the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at its election. The Company’s 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 the Company’s 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 the Company’s common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events, including certain distributions or a fundamental change. On or after March 15, 2023, the Senior Convertible Notes will be convertible at any time until the second scheduled trading day immediately preceding their September 15, 2023 maturity date. The Senior Convertible Notes will be convertible at an initial conversion rate of 76.3650 shares of the Company’s common stock per $1,000 principal amount of the Senior Convertible 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, the Company will increase the conversion rate for a holder who elects to convert its Senior Convertible Notes in connection with such corporate event or redemption in certain circumstances. As of December 31, 2019, none of the contingent conditions allowing holders of the Senior Convertible Notes to convert these notes had been met. In addition, the Company was in compliance with the terms of the indentures for the Senior Convertible Notes as of December 31, 2019.

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 the Company, along with its material subsidiaries (the “Guarantors”), which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors, subject to certain customary release provisions. The indentures governing the Notes contain customary events of default.

Subsequent to December 31, 2019, the Company repurchased a principal amount of $27.9 million of its outstanding Notes, for an aggregate cost of $22.2 million, including accrued interest, which will be reflected in the Company’s Consolidated Financial Statements subsequent to the year ended December 31, 2019.

Deferred financing costs. As of December 31, 2019, the Company had $22.9 million of deferred financing costs related to the Notes and the Revolving Credit Facilities. Deferred financing costs of $15.6 million related to the Notes are included in long-term debt on the Company’s Consolidated Balance Sheets as of December 31, 2019, and are being amortized over the respective terms of the Notes. Deferred financing costs of $4.8 million and $2.5 million related to the Oasis Credit Facility and OMP Credit Facility, respectively, are included in other assets on the Company’s Consolidated Balance Sheets at December 31, 2019, and are being amortized over the term of the Oasis Credit Facility and the OMP Credit Facility. Amortization of deferred financing costs recorded for the year ended December 31, 2019, 2018 and 2017 was $7.3 million, $7.6 million and $7.0 million, respectively. These costs are included in interest expense on the Company’s Consolidated Statements of Operations. For the year ended December 31, 2019, the Company’s interest expense also included $1.6 million for unamortized deferred financing costs related to the Oasis Credit Facility and the OMP Credit Facility, which were written off in proportion to the decrease in the borrowing base. For the year ended December 31, 2018, the Company’s interest expense also included $0.3 million for unamortized deferred financing costs related to the Oasis Credit Facility, which were written off in proportion to the two lenders leaving the bank group. No deferred financing costs related to the Revolving Credit Facilities were written off during the year ended December 31, 2017. Aforementioned, the gain (loss) on extinguishment of debt in the Company’s Consolidated Statements of Operations included unamortized deferred financing costs write-offs of $0.5 million and $4.0 million related to the repurchased Notes for the years ended December 31, 2019 and 2018, respectively. No deferred financing costs related to the Notes were written off during the year ended December 31, 2017.

14. Asset Retirement Obligations

The following table reflects the changes in the Company’s ARO during the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(In thousands)	
Asset retirement obligation — beginning of period	$ 52,449	$ 48,799
Liabilities incurred during period[(1)]	1,519	5,854
Liabilities settled during period[(2)]	(770)	(4,944)
Accretion expense during period[(1)(3)]	2,939	2,657
Revisions to estimates	647	83
Asset retirement obligation — end of period	$ 56,784	$ 52,449

(1) Includes costs for wells acquired in the Permian Basin Acquisition (see Note 10—Acquisitions) as of December 31, 2018.
(2) Liabilities settled during the years ended December 31, 2019 and 2018 included ARO related to sold properties (see Note 11—Divestitures).
(3) Included in depreciation, depletion and amortization on the Company’s Consolidated Statements of Operations.

At December 31, 2019 and 2018, the current portion of the total ARO balance was approximately $0.5 million and $0.1 million, respectively, and is included in accrued liabilities on the Company’s Consolidated Balance Sheets.

15. Income Taxes

The Company's income tax benefit consists of the following:

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Current:			
Federal	$ (43)	$ (70)	$ (420)
State	27	93	—
	(16)	23	(420)
Deferred:			
Federal	(28,148)	(3,553)	(199,370)
State	(4,551)	(2,313)	(3,514)
	(32,699)	(5,866)	(202,884)
Total income tax benefit	$ (32,715)	$ (5,843)	$ (203,304)

The reconciliation of income taxes calculated at the U.S. federal tax statutory rate to the Company's effective tax rate for the years ended December 31, 2019, 2018 and 2017, is set forth below:

	Year Ended December 31,					
	2019		2018		2017	
	(%)	(In thousands)	(%)	(In thousands)	(%)	(In thousands)
U.S. federal tax statutory rate	21.00 %	$ (25,906)	21.00 %	$ (5,322)	35.00 %	$ (26,550)
State income taxes, net of federal income tax benefit	2.90 %	(3,573)	2.08 %	(527)	2.59 %	(1,966)
Effects of non-controlling interest	6.40 %	(7,895)	13.09 %	(3,317)	1.68 %	(1,278)
Non-deductible executive compensation	(1.70) %	2,094	(9.50) %	2,408	1.05 %	(792)
Equity-based compensation windfall (shortfall)	(1.75) %	2,163	(3.68) %	932	0.87 %	(659)
State deferred tax rate change	— %	—	13.73 %	(3,479)	0.36 %	(270)
Change in valuation allowance	— %	—	(6.74) %	1,707	— %	—
Impact of U.S. tax reform	— %	—	(7.34) %	1,859	226.61 %	(171,900)
Other	(0.33) %	402	0.41 %	(104)	(0.15) %	111
Annual effective tax benefit	26.52 %	$ (32,715)	23.05 %	$ (5,843)	268.01 %	$ (203,304)

Significant components of the Company's deferred tax assets and liabilities as of December 31, 2019 and 2018, were as follows:

	Year Ended December 31,	
	2019	2018
	(In thousands)	
Deferred tax assets		
Net operating loss carryforward	$ 191,022	$ 177,745
Bonus and equity-based compensation	8,799	8,436
Derivative instruments	3,946	—
Other tax attribute carryovers	1,643	856
Total deferred tax assets	205,410	187,037
Less: Valuation allowance	(2,915)	(2,863)
Total deferred tax assets, net	$ 202,495	$ 184,174
Deferred tax liabilities		
Oil and gas properties	$ 426,130	$ 423,270
Derivative instruments	—	22,834
Investment in partnerships	38,015	22,450
Other deferred tax liabilities	5,707	15,675
Total deferred tax liabilities	$ 469,852	$ 484,229
Total deferred tax liabilities, net	$ 267,357	$ 300,055

As of December 31, 2019, the Company had federal net operating loss carryforwards of $800.5 million, which expire between 2030 and 2039, and $642.0 million of state net operating loss carryforwards, which expire between 2020 and 2039. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be more likely than not, and when the future utilization of some portion of the carryforwards is determined not to be more likely than not a valuation allowance is provided to reduce the recorded tax benefits from such assets. As of December 31, 2019 and 2018, the Company's valuation allowance balance was $2.9 million for both years, against Montana net operating loss carryforwards and certain other tax attribute carryforwards as the benefit for those attributes is not expected to be realized prior to their expiration due to their short carryover periods, current economic conditions and expectations for the future. No valuation allowances are required for U.S. federal and North Dakota tax net operating loss carryforwards as they are expected to be fully utilized before their expiration.

Due to the adoption of ASU 2016-09, unrealized excess tax benefits of $10.6 million were realized in the cumulative-effect adjustment to retained earnings on the Company's Condensed Consolidated Balance Sheet in the first quarter of 2017 and increased the deferred tax asset.

Accounting for uncertainty in income taxes prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As of December 31, 2019 and 2018, the Company had no unrecognized tax benefits. With respect to income taxes, the Company's policy is to account for interest charges as interest expense and any penalties as tax expense in its Consolidated Statements of Operations. The Company files income tax returns in the U.S. federal jurisdiction and in North Dakota, Montana and Texas. The statute of limitation for the year ended December 31, 2019 will expire in 2023. The Company's earliest open year in its key jurisdictions is 2016 for both the U.S. federal jurisdiction and various U.S. states, however, net operating losses originating in 2010 and all subsequent periods are subject to examination when utilized.

16. Equity-Based Compensation

The Company has granted equity awards to its officers, employees and directors under the Amended and Restated 2010 Long Term Incentive Plan. The maximum number of shares available for grant under the Amended and Restated 2010 Long Term Incentive Plan is 16,050,000.

Restricted stock awards. The Company has granted restricted stock awards to its employees and directors under its Amended and Restated 2010 Long Term Incentive Plan, the majority of which vest over a three-year period. The fair value of restricted stock grants is based on the closing sales price of the Company's common stock on the date of grant or, if applicable, the date of modification. Compensation expense is recognized ratably over the requisite service period.

The following table summarizes information related to restricted stock held by the Company's employees and directors for the periods presented:

	Shares	Weighted Average Grant Date Fair Value per Share
Non-vested shares outstanding December 31, 2018	5,136,556	$ 10.81
Granted	4,059,225	6.61
Vested	(2,656,483)	9.52
Forfeited	(803,131)	8.42
Non-vested shares outstanding December 31, 2019	5,736,167	$ 8.77

Equity-based compensation expense recorded for restricted stock awards was $24.0 million, $20.1 million and $19.5 million for each of the years ended December 31, 2019, 2018 and 2017, respectively, and is included in general and administrative expenses on the Company's Consolidated Statements of Operations. The fair value of awards vested was $14.6 million, $17.3 million and $22.0 million for the years ended December 31, 2019, 2018 and 2017, respectively. The weighted average grant date fair value of restricted stock awards granted was $6.61 per share, $10.20 per share and $15.03 per share for the years ended December 31, 2019, 2018 and 2017, respectively. Unrecognized expense as of December 31, 2019 for all outstanding restricted stock awards was $27.0 million and will be recognized over a weighted average period of 1.7 years.

Performance share units. The Company has granted PSUs to its officers under its Amended and Restated 2010 Long Term Incentive Plan. The PSUs are awards of restricted stock units that may be earned based on the level of achievement with respect to the applicable performance metric, and each PSU that is earned represents the right to receive one share of the Company's common stock.

The Company accounted for the PSUs as equity awards pursuant to the FASB's authoritative guidance for share-based payments. The number of PSUs to be earned is subject to a market condition, which is based on a comparison of the total shareholder return ("TSR") achieved with respect to shares of the Company's common stock against the TSR achieved by a defined peer group at the end of the performance periods. Depending on the Company's TSR performance relative to the defined peer group, award recipients will earn between 0% and 200% of the initial PSUs granted. All compensation expense related to the PSUs will be recognized if the requisite performance period is fulfilled, even if the market condition is not achieved.

The following table summarizes information related to PSUs held by the Company's officers for the periods presented:

	Units	Weighted Average Grant Date Fair Value per Unit
Non-vested PSUs at December 31, 2018	2,032,212	$ 10.94
Granted	1,685,090	6.80
Vested	(423,953)	7.45
Forfeited	(266,125)	10.97
Non-vested PSUs at December 31, 2019	3,027,224	$ 9.12

Equity-based compensation expense recorded for PSUs for the years ended December 31, 2019, 2018 and 2017 was $9.0 million, $8.5 million and $6.7 million, respectively, and is included in general and administrative expenses on the Company's Consolidated Statements of Operations. The fair value of PSUs vested was $2.6 million and $5.3 million for the years ended December 31, 2019 and 2018, respectively. No PSUs vested during the year ended December 31, 2017. The weighted average grant date fair value of PSUs granted was $6.80 per share, $12.71 per share and $16.89 per share for the years ended December 31, 2019, 2018 and 2017, respectively. Unrecognized expense as of December 31, 2019 for all outstanding PSUs was $10.9 million and will be recognized over a weighted average period of 2.6 years.

The aggregate grant date fair value of the market-based awards was determined using a Monte Carlo simulation model. The Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probabilistic assessment. The key valuation assumptions for the Monte Carlo model are the forecast period, risk-free interest rates, stock price volatility, initial value, stock price on the date of grant and correlation coefficients. The risk-free interest rates are the U.S. Treasury bond rates on the date of grant that corresponds to the each performance period. The initial value is the average of the volume weighted average prices for the 30 trading days prior to the start of the performance cycle for the Company and each of its peers. Volatility is the standard deviation of the average percentage change in stock price over a historical period for the Company and each of its peers. The correlation coefficients are measures of the strength of the linear relationship between and amongst the Company and its peers estimated based on historical stock price data.

The following assumptions were used for the Monte Carlo model to determine the grant date fair value and associated equity-based compensation expense of the PSUs granted during the periods presented:

	2019	2018	2017
Forecast period (years)	2 - 4	2 - 4	2 - 4
Risk-free interest rates	2.55% - 2.56%	2.08% - 2.31%	1.18% - 1.66%
Oasis stock price volatility	71.17 %	72.88 %	17.16 %
Oasis initial value	$ 5.85	$ 8.82	$ 15.64
Oasis stock price on date of grant	$ 6.63	$ 9.27	$ 15.21

Associated tax benefit. For the years ended December 31, 2019, 2018 and 2017, the Company had an associated tax benefit of $7.8 million, $6.8 million and $6.3 million, respectively, related to all equity-based compensation.

OMP phantom unit awards. The Company has granted OMP Phantom Unit Awards to its employees under its Amended and Restated 2010 Long Term Incentive Plan in 2018 and 2019, and OMP granted OMP Phantom Unit Awards to employees of the Company under the OMP LTIP in 2017.

As of December 31, 2019, the aggregate number of common units that may be issued pursuant to any and all awards under the OMP LTIP is equal to 2,455,408 common units, subject to adjustment due to recapitalization or reorganization, or related to forfeitures or expiration of awards, as provided under the OMP LTIP. On January 1 of each calendar year following the adoption and prior to the expiration of the OMP LTIP, the total number of common units that may be issued pursuant to the OMP LTIP automatically increases by a number of common units equal to one percent of the number of common units outstanding on a fully diluted basis as of the close of business on the immediately preceding December 31 (calculated by adding to the number of common units outstanding, all outstanding securities convertible into common units on such date on an as converted basis). As a result of this adjustment, an additional 337,952 common units were reserved for issuance pursuant to awards under the OMP LTIP on January 1, 2020.

Each OMP Phantom Unit represents the right to receive, upon vesting of the award, a cash payment equal to the fair market value of one OMP common unit on the day prior to the date it vests (the "Vesting Date"). Award recipients are also entitled to Distribution Equivalent Rights ("DER") with respect to each OMP Phantom Unit received. Each DER represents the right to receive, upon vesting of the award, a cash payment equal to the value of the distributions paid on one OMP common unit between the Grant Date and the applicable Vesting Date. The OMP Phantom Unit Awards generally vest in equal installments each year over a three-year period from the date of grant, 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.

The OMP Phantom Unit Awards are accounted for as liability-classified awards since the awards will settle in cash, and equity-based compensation expense is accounted for under the fair value method in accordance with GAAP. Under the fair value method for liability-classified awards, compensation expense 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.

The following table summarizes information related to OMP Phantom Unit Awards held by certain employees of Oasis for the periods presented:

	Phantom Units	Weighted Average Grant Date Fair Value per Unit
Non-vested units outstanding December 31, 2018	143,089	$ 20.85
Granted	341,290	18.57
Vested	(46,334)	20.33
Forfeited	(76,043)	19.30
Non-vested units outstanding December 31, 2019	362,002	$ 19.09

Equity-based compensation expense recorded for the OMP Phantom Unit Awards for the years ended December 31, 2019, 2018 and 2017 was $2.5 million, $0.5 million and $0.1 million, respectively. The fair value of OMP Phantom Unit Awards vested was $0.8 million and $0.6 million for the years ended December 31, 2019 and 2018, respectively. No OMP Phantom Unit Awards vested during the year ended December 31, 2017. For the years ended December 31, 2019, 2018 and 2017, the weighted average grant date fair value of OMP Phantom Unit Awards granted was $18.57 per unit, $23.91 per unit and $16.40 per unit, respectively. As of December 31, 2019, unrecognized compensation cost for all outstanding OMP Phantom Unit Awards was $4.3 million, which is expected to be recognized over a weighted average period of 2.0 years.

OMP restricted unit awards. OMP has granted to independent directors of the general partner restricted unit awards under the OMP LTIP, which vest over a one-year period from the date of grant. These awards are accounted for as equity-classified awards since the awards will settle in common units upon vesting. Equity-based compensation expense is accounted for under the fair value method in accordance with GAAP. Under the fair value method for equity-classified awards, equity-based compensation expense is measured at the grant date based on the fair value of the award and is recognized over the vesting period.

The following table summarizes information related to restricted units held by certain directors of OMP for the periods presented:

	Restricted Units	Weighted Average Grant Date Fair Value per Unit
Non-vested units outstanding December 31, 2018	17,260	$ 17.55
Granted	16,170	18.57
Vested	(17,260)	17.55
Forfeited	—	—
Non-vested units outstanding December 31, 2019	16,170	$ 18.57

Equity-based compensation expense recorded for OMP restricted unit awards the years ended December 31, 2019, 2018 and 2017 was $0.4 million, $0.4 million and $0.1 million, respectively, and is included in general and administrative expenses on the Company's Consolidated Statements of Operations. The fair value of OMP restricted unit awards vested was $0.3 million for the years ended December 31, 2019 and 2018, respectively. No OMP restricted unit awards vested during the year ended December 31, 2017. The weighted average grant date fair value of OMP restricted stock awards granted was $18.57 per unit, $17.55 per unit and $17.00 per unit for the years ended December 31, 2019, 2018 and 2017, respectively. Unrecognized expense as of December 31, 2019 for all outstanding OMP restricted unit awards was $0.01 million, and will be recognized over a weighted average period of 0.1 years.

Class B units in OMP GP. In May 2017, OMP GP granted restricted Class B Units to certain employees, including OMP's executive officers, as consideration for services to Oasis, which vest over a ten-year period. The restricted Class B Units represent 9% of the outstanding units of OMP GP as of December 31, 2019. Compensation expense is recognized ratably over the requisite service period. Equity-based compensation expense recorded for the Class B Units was $0.2 million, $0.3 million and $0.2 million for the years ended December 31, 2019, 2018 and 2017, respectively, and is included in general and administrative expenses on the Company's Consolidated Statements of Operations.

17. Common Stock

Dividends. The Company has not paid any cash dividends since its inception. Covenants contained in the Revolving Credit Facilities and the indentures governing the Company's Senior Notes restrict the payment of cash dividends on its common stock. The Company currently intends to retain all future earnings for the development of its business, and the Company does not anticipate declaring or paying any cash dividends to holders of its common stock in the foreseeable future.

18. Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing the earnings (loss) attributable to Oasis common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings (loss) per share includes the potential dilutive impact of unvested restricted stock awards, contingently issuable shares related to PSUs and senior convertible notes during the periods presented, unless their effect is anti-dilutive. There are no adjustments made to income (loss) attributable to Oasis available to common stockholders in the calculation of diluted earnings (loss) per share.

The following is a calculation of the basic and diluted weighted average shares outstanding for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Basic weighted average common shares outstanding	315,002	307,480	234,986
Dilutive effect of restricted stock awards and PSUs[1]	—	—	2,889
Diluted weighted average common shares outstanding	315,002	307,480	237,875

(1) No unvested stock awards were included in computing loss per share for the years ended December 31, 2019 and 2018 because the effect was anti-dilutive.

During the years ended December 31, 2019 and 2018, the Company incurred a net loss, and therefore the diluted loss per share calculation for those periods excludes the anti-dilutive effect of unvested stock awards. In addition, the diluted earnings per share calculation for the year ended December 31, 2017 excludes the dilutive effect of unvested stock awards that were anti-dilutive under the treasury stock method. The following is a calculation of weighted average common shares excluded from diluted earnings (loss) per share due to the anti-dilutive effect:

	Year Ended December 31,		
	2019	**2018**	**2017**
		(In thousands)	
Restricted stock awards and PSUs	9,242	6,980	2,881

The Company issued its Senior Convertible Notes in September 2016 (see Note 13—Long-Term Debt). The Company has the option to settle conversions of its Senior Convertible Notes with cash, shares of common stock or a combination of cash and common stock at its election. The Company's intent is to settle the principal amount of the Senior Convertible Notes in cash upon conversion. As a result, only the amount by which the conversion value exceeds the aggregate principal amount of the notes (conversion spread) is considered in the diluted earnings per share computation under the treasury stock method. As of December 31, 2019, 2018 and 2017, the conversion value did not exceed the principal amount of the notes, and accordingly, there was no impact to diluted earnings per share for years ended December 31, 2019, 2018 and 2017.

19. Business Segment Information

As of December 31, 2019, the Company had three reportable segments: exploration and production, midstream and well services. The Company's exploration and production segment is engaged in the acquisition and development of oil and gas properties. Revenues for the exploration and production segment are derived from the sale of crude oil and natural gas production. The Company's midstream segment performs produced and flowback water gathering and disposal services, fresh water services, natural gas gathering and processing and crude oil gathering and transportation and other midstream services for crude oil and natural gas wells operated by the Company as well as third-party operated wells. The Company's well services segment generates revenue from well completion services, product sales and equipment rentals for the Company's crude oil and natural gas wells. In conjunction with its planned Well Services Exit in the first quarter of 2020, the Company expects to eliminate its well services segment and report the remaining equipment rentals activity within its exploration and production segment. The revenues and expenses related to work performed by OMP, OMS and OWS for the Company's ownership interests are eliminated in consolidation, and only the revenues and expenses related to non-affiliated owners are included in the Company's Consolidated Statements of Operations. The Company's corporate activities have been allocated to the supported business segments accordingly. Management evaluates the performance of the Company's business segments based on operating income, which is defined as segment operating revenues less operating expenses, including depreciation, depletion and amortization ("DD&A").

The following table summarizes financial information for the Company's three business segments for the periods presented:

	Exploration and Production		Midstream		Well Services		Eliminations		Consolidated
					(In thousands)				
Year Ended December 31, 2019									
Revenues from external customers	$	1,817,532	$	212,238	$	41,974	$	—	$ 2,071,744
Inter-segment revenues		—		276,189		79,686		(355,875)	—
Total revenues		1,817,532		488,427		121,660		(355,875)	2,071,744
Operating income (loss)		(71,191)		241,161		(2,024)		(13,523)	154,423
Other income (expense), net		(260,878)		(17,065)		158		—	(277,785)
Income (loss) before income taxes including non-controlling interests	$	(332,069)	$	224,096	$	(1,866)	$	(13,523)	$ (123,362)
Total assets[1]	$	6,567,735	$	1,101,401	$	25,866	$	(195,749)	$ 7,499,253
Property, plant and equipment, net		6,127,952		1,078,903		1,670		(230,749)	6,977,776
Capital expenditures[2]		644,798		212,381		282		(14,093)	843,368
Depreciation, depletion and amortization		766,959		37,152		13,631		(30,550)	787,192
General and administrative		118,701		31,737		26,233		(33,165)	143,506
Equity-based compensation		32,251		1,744		1,397		(1,785)	33,607
Impairment		5,856		—		4,401		—	10,257
Year Ended December 31, 2018									
Revenues from external customers	$	2,136,735	$	124,137	$	61,075	$	—	$ 2,321,947
Inter-segment revenues		—		162,505		144,544		(307,049)	—
Total revenues		2,136,735		286,642		205,619		(307,049)	2,321,947
Operating income (loss)		(25,027)		143,126		30,988		(30,075)	119,012
Other income (expense), net		(142,265)		(2,125)		35		—	(144,355)
Income (loss) before income taxes including non-controlling interests	$	(167,292)	$	141,001	$	31,023	$	(30,075)	$ (25,343)
Total assets[1]	$	6,838,987	$	920,619	$	48,150	$	(181,614)	$ 7,626,142
Property, plant and equipment, net		6,311,566		893,285		38,871		(216,613)	7,027,109
Capital expenditures[2]		1,948,076		277,626		7,831		(30,080)	2,203,453
Depreciation, depletion and amortization		618,402		29,282		15,698		(27,086)	636,296
General and administrative		102,482		24,700		23,282		(29,118)	121,346
Equity-based compensation		27,910		1,547		1,588		(1,772)	29,273
Impairment		384,228		—		—		—	384,228

Year Ended December 31, 2017										
Revenues from external customers	$	1,168,176	$	72,752	$	52,791	$	—	$	1,293,719
Inter-segment revenues		—		113,047		95,345		(208,392)		—
Total revenues		1,168,176		185,799		148,136		(208,392)		1,293,719
Operating income		40,694		102,377		15,057		(14,160)		143,968
Other income (expense)		(219,823)		(37)		34		—		(219,826)
Income (loss) before income taxes including non-controlling interests	$	(179,129)	$	102,340	$	15,091	$	(14,160)	$	(75,858)
Total assets(1)	$	6,058,054	$	663,614	$	52,800	$	(151,539)	$	6,622,929
Property, plant and equipment, net		5,663,323		649,923		46,779		(186,539)		6,173,486
Capital expenditures(2)		602,734		235,090		12,537		(14,157)		836,204
Depreciation, depletion and amortization		519,853		15,999		12,939		(17,989)		530,802
General and administrative		77,560		19,583		24,359		(29,705)		91,797
Equity-based compensation		25,436		1,461		1,264		(1,627)		26,534
Impairment		6,887		—		—		—		6,887

(1) Intercompany receivables (payables) for all segments were reclassified to capital contributions from (distributions to) parent and not included in total assets.

(2) Capital expenditures reflected in the table above differ from the amounts for capital expenditures and acquisitions of oil and gas properties shown in the Company's Consolidated Statements of Cash Flows 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 Consolidated Statements of Cash Flows are presented on a cash basis. Acquisitions totaled $21.0 million, $951.9 million and $54.0 million for the years ended December 31, 2019, 2018 and 2017, respectively, in the exploration and production segment. Additionally, capital expenditures 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.

20. Leases

As discussed in Note 2 — Summary of Significant Accounting Policies, the Company adopted ASC 842 as of January 1, 2019 using the modified retrospective method, which resulted in the Company recognizing operating lease ROU assets and lease liabilities of $31.1 million and $37.1 million, respectively. In addition, the Company recognized offsetting finance lease ROU assets and lease liabilities of $6.0 million. There was no impact to the opening equity balance as a result of adoption as the difference between the asset and liability balance is attributable to reclassifications of pre-existing balances, such as deferred rent, into the lease asset balance. Prior period amounts are not adjusted and continue to be reported in accordance with the previous guidance, Accounting Standards Codification 840 ("ASC 840").

In accordance with the adoption of ASC 842, management determines whether an arrangement is a lease at its inception. The Company's operating and finance leases consist primarily of office space, drilling rigs, vehicles and other property and equipment used in its operations. The operating lease ROU asset also includes any lease incentives received in the recognition of the present value of future lease payments. The Company considers renewal and termination options in determining the lease term used to establish its ROU assets and lease liabilities to the extent the Company is reasonably certain to exercise the renewal or termination. The Company's lease agreements do not contain any material residual value guarantees or material restrictive covenants.

As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of future lease payments. The Company has determined their respective incremental borrowing rates based upon the rate of interest that would have been paid on a collateralized basis over similar tenors to that of the leases.

The Company’s components of lease costs were as follows:

	Year Ended December 31, 2019
	(In thousands)
Operating lease costs	$ 26,341
Variable lease costs(1)	9,189
Short-term lease costs	4,657
Finance lease costs:	
Amortization of ROU assets	2,543
Interest on lease liabilities	260
Total lease costs	$ 42,990

(1) Based on payments made by the Company to lessors for the right to use an underlying asset that vary because of changes in circumstances occurring after the commencement date, other than the passage of time, such as property taxes, operating and maintenance costs, which do not depend on an index or rate.

The amounts disclosed herein include costs associated with properties operated by the Company that are presented on a gross basis and do not reflect the Company’s net proportionate share of such amounts. A portion of these costs have been or will be billed to other working interest owners.

The Company’s share of operating, variable and short-term lease costs are either capitalized and included in property, plant and equipment on the Company’s Consolidated Balance Sheets or are recognized in the Company’s Consolidated Statements of Operations in lease operating expenses, midstream expenses and general and administrative expenses, as applicable. The finance lease costs for the amortization of ROU assets and the interest on lease liabilities disclosed above are included in depreciation, depletion and amortization and interest expense, net of capitalized interest, respectively, on the Company’s Consolidated Statements of Operations.

For the years ended December 31, 2018 and December 31, 2017, the Company had operating leases for office space and other property and equipment used in its operations, which it accounted for as operating leases in accordance with GAAP under ASC 840. For the years ended December 31, 2018 and December 31, 2017, the Company incurred operating rental expenses of $10.6 million and $6.9 million, respectively, which were included in general and administrative expenses on its Consolidated Statements of Operations.

As of December 31, 2019, maturities of the Company’s lease liabilities were as follows:

	Operating Leases	Finance Leases
	(In thousands)	
2020	$ 7,001	$ 2,585
2021	2,704	2,038
2022	3,073	1,367
2023	2,365	274
2024	2,362	45
Thereafter	10,440	639
Total future lease payments	27,945	6,948
Less: Imputed interest	3,848	578
Present value of future lease payments	$ 24,097	$ 6,370

As of December 31, 2018, future minimum annual rental commitments under non-cancelable leases under ASC 840 were as follows:

	(In thousands)
2019	$ 8,723
2020	7,009
2021	6,005
2022	5,130
2023	4,361
Thereafter	13,134
Total future minimum lease payments	$ 44,362

Supplemental balance sheet information related to the Company's leases were as follows:

	Balance Sheet Location	December 31, 2019
		(In thousands)
Assets		
Operating lease assets	Operating right-of-use assets	$ 18,497
Finance lease assets[(1)]	Other assets	6,303
Total lease assets		$ 24,800
Liabilities		
Current		
Operating lease liabilities	Current operating lease liabilities	$ 6,182
Finance lease liabilities	Other current liabilities	2,413
Long-term		
Operating lease liabilities	Operating lease liabilities	17,915
Finance lease liabilities	Other liabilities	3,958
Total lease liabilities		$ 30,468

(1) Finance lease ROU assets are recorded net of accumulated amortization of $2.3 million as of December 31, 2019.

Supplemental cash flow information and non-cash transactions related to the Company's leases were as follows:

	December 31, 2019
	(In thousands)
Cash paid for amounts included in the measurement of lease liabilities	
Operating cash flows from operating leases	$ 30,316
Operating cash flows from finance leases	260
Financing cash flows from finance leases	2,382
ROU assets obtained in exchange for lease obligations	
Operating leases	$ 12,746
Finance leases	3,433

Weighted-average remaining lease terms and discount rates for the Company's leases were as follows:

	As of December 31, 2019
Operating Leases	
Weighted average remaining lease term	7.1 years
Weighted average discount rate	4.1 %
Finance Leases	
Weighted average remaining lease term	4.1 years
Weighted average discount rate	3.9 %

21. Significant Concentrations

Major customers. For the year ended December 31, 2019, sales to Phillips 66 Company accounted for approximately 14% of the Company's total sales. 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 the Company's total sales. No other purchasers accounted for more than 10% of the Company's total sales for the years ended December 31, 2019 and 2017. Total sales include revenues from the Company's exploration and production segment only, as OMS and OWS provide services to OPNA.

Substantially all of the Company's accounts receivable result from sales of crude oil, natural gas and NGLs as well as joint interest billings ("JIB") to third-party companies who have working interest payment obligations in projects completed by the Company. This concentration of customers and joint interest owners may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions, including the current downturn in crude oil prices. Management believes that the loss of any of these purchasers would not have a material adverse effect on the Company's operations, as there are a number of alternative crude oil, natural gas and NGL purchasers in the Company's producing regions.

22. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of December 31, 2019. The commitments under these arrangements are not recorded in the accompanying Consolidated Balance Sheets. The amounts disclosed represent undiscounted cash flows on a gross basis and no inflation elements have been applied.

Volume commitment agreements. As of December 31, 2019, the Company had certain agreements with an aggregate requirement to deliver, transport or purchase a minimum quantity of approximately 34.9 MMBbl of crude oil, 35.0 MMBbl of NGLs, 827.6 Bcf of natural gas and 14.9 MMBbl of water, prior to any applicable volume credits, within specified timeframes, all of which are 25 years or less. These amounts are recognized as marketing, transportation and gathering expense in the Company's Consolidated Statements of Operations. The future commitments under certain agreements cannot be estimated as they are based on fixed differentials relative to a commodity index price under the agreements as compared to the differential relative to a commodity index price for the production month.

The estimable future commitments under these volume commitment agreements as of December 31, 2019 are as follows:

	(In thousands)
2020	$ 82,515
2021	95,074
2022	107,004
2023	91,649
2024	78,013
Thereafter	140,282
	$ 594,537

Subsequent to December 31, 2019, the Company entered into a new agreement to deliver additional volumes of water within a specified timeframe, which is ten years or less. The estimable future total commitment under this volume commitment agreement was approximately $3.8 million.

The Company enters into long-term contracts to provide production flow assurance in over-supplied basins and/or areas with limited infrastructure. This strategic tactic provides for optimization of transportation and processing costs. As properties are undergoing development activities, the Company may experience temporary delivery or transportation shortfalls until production volumes grow to meet or exceed the minimum volume commitments. The Company recognizes any monthly deficiency payments in the period in which the underdelivery takes place and the related liability has been incurred. The table above does not include any such deficiency payments that may be incurred under the Company's physical delivery contracts, since it cannot be predicted with accuracy the amount and timing of any such penalties incurred.

Lease commitments. The Company has various operating and finance lease commitments that consists primarily of offices, drilling rigs, vehicles and other property and equipment used in its operations. See Note 20—Leases for additional information.

Litigation. The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. When the Company determines that a loss is probable of occurring and is reasonably estimable, the Company accrues an undiscounted liability for such contingencies based on its best estimate using information available at the time. The Company discloses contingencies where an adverse outcome may be material, or in the judgment of management, the matter should otherwise be disclosed.

During the year ended December 31, 2019, a loss accrual was recorded in the amount of $20 million, which the Company believes is the estimable amount of loss that could potentially be incurred from its pending legal proceedings based upon currently available information. This amount was recognized in accrued liabilities in the Company's Consolidated Balance Sheet and general and administrative expenses in the Company's Consolidated Statements of Operations.

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 OMS, 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 natural 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, Bobcat DevCo and Beartooth DevCo 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 OMP as a defendant, asserting that it was created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On July 2, 2019, Oasis, OPNA, OMS, OMP, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo LLC (collectively "Oasis Entities") counterclaimed against Mirada for a judgment declaring that Oasis Entities are not obligated to purchase, manage, gather, transport, compress, process, market, sell or otherwise handle Mirada's proportionate share of oil and gas produced from OPNA-operated wells. The counterclaim also seeks attorney's fees, costs and expenses.

On November 1, 2019, Mirada filed a sixth amended petition that stated that Mirada seeks in excess of $200 million in damages and asserted that OMS is an agent of OPNA and OPNA, OMS, OMP, Bighorn DevCo, Bobcat DevCo and Beartooth DevCo LLC are agents of Oasis. Mirada also changed its allegation that it may elect a new operator for the subject wells to instead allege that Mirada may remove Oasis as operator.

On November 1, 2019, the Oasis Entities amended their counterclaim against Mirada for a judgment declaring that a provision in one of the agreements does not incorporate by reference any provisions in a certain participation agreement and joint operating agreement. The additional counterclaim also seeks attorney's fees, costs and expenses. On the same day, the Oasis Entities filed an amended answer asserting additional defenses against Mirada's claims.

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.

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 is scheduled for May 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.

Solomon litigation. On or about August 28, 2019, Oasis Petroleum LLC, a wholly-owned subsidiary of the Company ("OP LLC"), was named as a defendant in the lawsuit styled *Andrew Solomon, on behalf of himself and those similarly situated vs. Oasis Petroleum, LLC*, pending in the United States District Court for the District of North Dakota. The lawsuit alleged violations of the federal Fair Labor Standards Act (the "FLSA") and Title 29 of the North Dakota Century Code ("Title 29") as the result of OP LLC's alleged practice of paying the plaintiff and similarly situated current and former employees overtime at rates less than required by applicable law, or failing to pay for certain overtime hours worked. The lawsuit requested that: (i) its federal claims be advanced as a collective action, with a class of all operators, technicians and all other employees in substantially similar positions employed by OP LLC who were paid hourly for at least one week during the three year period prior to the commencement of the lawsuit, who worked 40 or more hours in at least one workweek and/or eight or more hours on at least one workday; and (ii) its state claims be advanced as a class action, with a class of all Operators, Technicians, and all other employees in substantially similar positions employed by OP LLC in North Dakota during the two year period prior to the commencement of the lawsuit, who worked 40 or more hours in at least one workweek and/or worked eight or more hours in a day on at least one workday. No motion has been filed for class certification, and the Company cannot predict whether such a motion will be filed or a class certified.

The Company believes that Mr. Solomon's claims are without merit and that OP LLC has complied with its obligations under the FLSA and Title 29. OP LLC has filed an answer denying all of Mr. Solomon's claims and intends to vigorously defend against the claims. The Company cannot predict or guarantee the ultimate outcome or resolutions 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.

23. Subsequent Events

The Company has evaluated the period after the balance sheet date, noting no subsequent events or transactions that required recognition or disclosure in the financial statements, other than as previously disclosed.

24. Condensed Consolidating Financial Information

The Notes (see Note 13—Long-Term Debt) are guaranteed on a senior unsecured basis by the Guarantors, which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors. Certain of the Company's operating units, including OMP (see Note 3—Oasis Midstream Partners), which is accounted for on a consolidated basis, do not guarantee the Notes ("Non-Guarantor Subsidiaries").

The following financial information reflects consolidating financial information of the parent company, Oasis Petroleum Inc. ("Issuer"), its Guarantors on a combined basis (the "Combined Guarantor Subsidiaries") and the Non-Guarantor Subsidiaries on a combined basis (the "Combined Non-Guarantor Subsidiaries"), prepared on the equity basis of accounting. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantors operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantors because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantors. The assignment of the Delaware Midstream Assets to Panther DevCo in November 2019 represents the transfer of a business from a Guarantor Subsidiary to a Non-Guarantor Subsidiary, and is retrospectively reflected in the Combined Non-Guarantor Subsidiaries financial information and removed from the Combined Guarantors Subsidiaries financial information for all periods presented.

During 2019, the Company identified errors primarily relating to the presentation of non-controlling interests and equity in earnings of subsidiaries in the financial information of the Combined Guarantor Subsidiaries and the related intercompany eliminations.

- *Condensed Consolidating Balance Sheet.* As of December 31, 2018, it was determined that (1) in the Issuer's financial information, investment in and advances to subsidiaries and Oasis share of stockholders' equity were both overstated by $9.6 million, (2) in the Combined Guarantor Subsidiaries financial information, investment in and advances to subsidiaries and non-controlling interests were overstated by $11.1 million and $184.3 million, respectively, and Oasis share of stockholders' equity was understated by $173.2 million and (3) in the intercompany eliminations financial information, investments in and advances to subsidiaries and non-controlling interests were understated by $20.7 million and $184.3 million, respectively, and Oasis share of stockholders' equity was overstated by $163.6 million.

- *Condensed Consolidated Statements of Operations.* For the year ended December 31, 2018, it was determined that equity in earnings of subsidiaries and net income attributable to non-controlling interests were overstated by $24.9 million and $15.8 million, respectively, in the Combined Guarantor Subsidiaries financial information and understated by $24.9 million and $15.8 million, respectively, in the intercompany eliminations financial information. For the year ended December 31, 2017, it was determined that equity in earnings of subsidiaries and net income attributable to non-controlling interests were overstated by $5.6 million and $3.7 million, respectively, in the Combined Guarantor Subsidiaries financial information and understated by $5.6 million and $3.7 million, respectively, in the intercompany eliminations financial information.
- *Condensed Consolidated Statement of Cash Flows.* For the year ended December 31, 2018, it was determined that cash paid for distributions to non-controlling interests was understated by $114.8 million in the Combined Guarantor Subsidiaries financial information and overstated by $114.8 million in the intercompany eliminations financial information, with the offsetting impacts in investment in subsidiaries / capital contributions from parent.

These errors in the condensed consolidated financial statements, which the Company has determined are not material to this disclosure, were all eliminated in consolidation and therefore have no impact on the Company's consolidated financial position, results of operations or cash flows. The Company has revised the consolidating financial statements as of December 31, 2018 and 2017 to reflect the correction of these errors.

Condensed Consolidating Balance Sheet

	December 31, 2019				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
			(In thousands)		
ASSETS					
Current assets					
Cash and cash equivalents	$ 146	$ 15,705	$ 4,168	$ —	$ 20,019
Accounts receivable, net	—	365,212	5,969	—	371,181
Accounts receivable - affiliates	499,209	76,179	77,571	(652,959)	—
Inventory	—	35,259	—	—	35,259
Prepaid expenses	550	7,538	1,923	—	10,011
Derivative instruments	—	535	—	—	535
Other current assets	—	208	138	—	346
Total current assets	499,905	500,636	89,769	(652,959)	437,351
Property, plant and equipment					
Oil and gas properties (successful efforts method)	—	9,485,504	—	(22,466)	9,463,038
Other property and equipment	—	124,150	1,155,503	—	1,279,653
Less: accumulated depreciation, depletion, amortization and impairment	—	(3,665,933)	(98,982)	—	(3,764,915)
Total property, plant and equipment, net	—	5,943,721	1,056,521	(22,466)	6,977,776
Assets held for sale, net	—	21,628	—	—	21,628
Investments in and advances to subsidiaries	4,888,257	382,795	—	(5,271,052)	—
Derivative instruments	—	639	—	—	639
Deferred income taxes	249,646	—	—	(249,646)	—
Long-term inventory	—	13,924	—	—	13,924
Operating right-of-use assets	—	13,290	5,207	—	18,497
Other assets	—	26,266	3,172	—	29,438
Total assets	$ 5,637,808	$ 6,902,899	$ 1,154,669	$ (6,196,123)	$ 7,499,253
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities					
Accounts payable	$ —	$ 16,911	$ 1,037	$ —	$ 17,948
Accounts payable - affiliates	49,040	576,780	27,139	(652,959)	—
Revenues and production taxes payable	—	231,649	1,441	—	233,090
Accrued liabilities	50	230,819	50,210	—	281,079
Accrued interest payable	36,507	373	508	—	37,388
Derivative instruments	—	19,695	—	—	19,695
Advances from joint interest partners	—	4,598	—	—	4,598
Current operating lease liabilities	—	3,177	3,005	—	6,182
Other current liabilities	—	2,430	594	(121)	2,903
Total current liabilities	85,597	1,086,432	83,934	(653,080)	602,883
Long-term debt	1,916,073	337,000	458,500	—	2,711,573
Deferred income taxes	—	517,003	—	(249,646)	267,357
Asset retirement obligations	—	54,558	1,747	—	56,305
Derivative instruments	—	120	—	—	120
Operating lease liabilities	—	15,699	2,216	—	17,915

Other liabilities	—	3,830	3,644	(1,455)	6,019
Total liabilities	2,001,670	2,014,642	550,041	(904,181)	3,662,172
Stockholders’ equity					
Oasis share of stockholders’ equity	3,636,138	4,888,257	292,370	(5,180,627)	3,636,138
Non-controlling interests	—	—	312,258	(111,315)	200,943
Total stockholders’ equity	3,636,138	4,888,257	604,628	(5,291,942)	3,837,081
Total liabilities and stockholders’ equity	$ 5,637,808	$ 6,902,899	$ 1,154,669	$ (6,196,123)	$ 7,499,253

Condensed Consolidating Balance Sheet

	December 31, 2018				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
			(In thousands)		
ASSETS					
Current assets					
Cash and cash equivalents	$ 179	$ 15,362	$ 6,649	$ —	$ 22,190
Accounts receivable, net	—	385,121	2,481	—	387,602
Accounts receivable - affiliates	643,382	76,127	81,022	(800,531)	—
Inventory	—	33,106	22	—	33,128
Prepaid expenses	373	9,206	1,418	—	10,997
Derivative instruments	—	99,930	—	—	99,930
Intangible assets, net	—	125	—	—	125
Other current assets	—	183	—	—	183
Total current assets	643,934	619,160	91,592	(800,531)	554,155
Property, plant and equipment					
Oil and gas properties (successful efforts method)	—	8,923,291	—	(11,102)	8,912,189
Other property and equipment	—	209,194	942,578	—	1,151,772
Less: accumulated depreciation, depletion, amortization and impairment	—	(2,974,122)	(62,730)	—	(3,036,852)
Total property, plant and equipment, net	—	6,158,363	879,848	(11,102)	7,027,109
Investments in and advances to subsidiaries	4,900,528	362,266	—	(5,262,794)	—
Derivative instruments	—	6,945	—	—	6,945
Deferred income taxes	219,670	—	—	(219,670)	—
Long-term inventory	—	12,260	—	—	12,260
Other assets	—	23,221	2,452	—	25,673
Total assets	$ 5,764,132	$ 7,182,215	$ 973,892	$ (6,294,097)	$ 7,626,142
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities					
Accounts payable	$ —	$ 18,567	$ 1,599	$ —	$ 20,166
Accounts payable - affiliates	43,113	724,404	33,014	(800,531)	—
Revenues and production taxes payable	—	216,114	581	—	216,695
Accrued liabilities	71	270,626	60,954	—	331,651
Accrued interest payable	37,096	502	442	—	38,040
Derivative instruments	—	84	—	—	84
Advances from joint interest partners	—	5,140	—	—	5,140
Total current liabilities	80,280	1,235,437	96,590	(800,531)	611,776
Long-term debt	1,949,276	468,000	318,000	—	2,735,276
Deferred income taxes	—	519,725	—	(219,670)	300,055
Asset retirement obligations	—	50,754	1,630	—	52,384
Derivative instruments	—	20	—	—	20
Other liabilities	—	7,751	—	—	7,751
Total liabilities	2,029,556	2,281,687	416,220	(1,020,201)	3,707,262
Stockholders' equity					
Oasis share of stockholders' equity	3,734,576	4,900,528	244,857	(5,145,385)	3,734,576

Non-controlling interests	—	—	312,815	(128,511)	184,304
Total stockholders' equity	3,734,576	4,900,528	557,672	(5,273,896)	3,918,880
Total liabilities and stockholders' equity	$ 5,764,132	$ 7,182,215	$ 973,892	$ (6,294,097)	$ 7,626,142

Condensed Consolidating Statement of Operations

	Year Ended December 31, 2019				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
			(In thousands)		
Revenues					
Oil and gas revenues	$ —	$ 1,407,809	$ —	$ 962	$ 1,408,771
Purchased oil and gas sales	—	408,791	—	—	408,791
Midstream revenues	—	73,558	410,191	(271,541)	212,208
Well services revenues	—	41,974	—	—	41,974
Total revenues	—	1,932,132	410,191	(270,579)	2,071,744
Operating expenses					
Lease operating expenses	—	287,426	—	(64,042)	223,384
Midstream expenses	—	66,545	110,052	(114,451)	62,146
Well services expenses	—	28,761	—	—	28,761
Marketing, transportation and gathering expenses	—	173,254	—	(44,448)	128,806
Purchased oil and gas expenses	—	409,180	—	—	409,180
Production taxes	—	112,592	—	—	112,592
Depreciation, depletion and amortization	—	771,836	36,358	(21,002)	787,192
Exploration expenses	—	6,658	—	—	6,658
Rig termination	—	384	—	—	384
Impairment	—	10,257	—	—	10,257
General and administrative expenses	16,637	112,709	31,009	(16,849)	143,506
Total operating expenses	16,637	1,979,602	177,419	(260,792)	1,912,866
Loss on sale of properties	—	(4,455)	—	—	(4,455)
Operating income (loss)	(16,637)	(51,925)	232,772	(9,787)	154,423
Other income (expense)					
Equity in earnings (loss) of subsidiaries	(13,898)	167,848	—	(153,950)	—
Net loss on derivative instruments	—	(106,314)	—	—	(106,314)
Interest expense, net of capitalized interest	(132,000)	(26,685)	(17,538)	—	(176,223)
Gain on extinguishment of debt	4,312	—	—	—	4,312
Other income (expense)	3	440	(3)	—	440
Total other income (expense), net	(141,583)	35,289	(17,541)	(153,950)	(277,785)
Income (loss) before income taxes	(158,220)	(16,636)	215,231	(163,737)	(123,362)
Income tax benefit	29,977	2,738	—	—	32,715
Net income (loss) including non-controlling interests	(128,243)	(13,898)	215,231	(163,737)	(90,647)
Less: Net income attributable to non-controlling interests	—	—	93,111	(55,515)	37,596
Net income (loss) attributable to Oasis	$ (128,243)	$ (13,898)	$ 122,120	$ (108,222)	$ (128,243)

Condensed Consolidating Statement of Operations

	Year Ended December 31, 2018				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
			(In thousands)		
Revenues					
Oil and gas revenues	$ —	$ 1,590,024	$ —	$ —	$ 1,590,024
Purchased oil and gas sales	—	550,344	—	—	550,344
Midstream revenues	—	4,620	273,770	(157,886)	120,504
Well services revenues	—	61,075	—	—	61,075
Total revenues	—	2,206,063	273,770	(157,886)	2,321,947
Operating expenses					
Lease operating expenses	—	248,257	—	(54,345)	193,912
Midstream expenses	—	3,482	71,118	(41,842)	32,758
Well services expenses	—	41,200	—	—	41,200
Marketing, transportation and gathering expenses	—	131,340	—	(24,147)	107,193
Purchased oil and gas expenses	—	553,521	—	(60)	553,461
Production taxes	—	133,696	—	—	133,696
Depreciation, depletion and amortization	—	623,349	28,409	(15,462)	636,296
Exploration expenses	—	27,432	—	—	27,432
Impairment	—	384,228	—	—	384,228
General and administrative expenses	30,003	79,742	23,897	(12,296)	121,346
Total operating expenses	30,003	2,226,247	123,424	(148,152)	2,231,522
Gain on sale of properties	—	28,587	—	—	28,587
Operating income (loss)	(30,003)	8,403	150,346	(9,734)	119,012
Other income (expense)					
Equity in earnings of subsidiaries	103,586	122,222	—	(225,808)	—
Net gain on derivative instruments	—	28,457	—	—	28,457
Interest expense, net of capitalized interest	(131,134)	(25,371)	(2,580)	—	(159,085)
Loss on extinguishment of debt	(13,848)	—	—	—	(13,848)
Other income (expense)	1	134	(14)	—	121
Total other income (expense), net	(41,395)	125,442	(2,594)	(225,808)	(144,355)
Income (loss) before income taxes	(71,398)	133,845	147,752	(235,542)	(25,343)
Income tax benefit (expense)	36,102	(30,259)	—	—	5,843
Net income (loss) including non-controlling interests	(35,296)	103,586	147,752	(235,542)	(19,500)
Less: Net income attributable to non-controlling interests	—	—	96,354	(80,558)	15,796
Net income (loss) attributable to Oasis	$ (35,296)	$ 103,586	$ 51,398	$ (154,984)	$ (35,296)

Condensed Consolidating Statement of Operations

	Year Ended December 31, 2017				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
			(In thousands)		
Revenues					
Oil and gas revenues	$ —	$ 1,034,634	$ —	$ —	$ 1,034,634
Purchased oil and gas sales	—	133,542	—	—	133,542
Midstream revenues	—	46,649	59,821	(33,718)	72,752
Well services revenues	—	52,791	—	—	52,791
Total revenues	—	1,267,616	59,821	(33,718)	1,293,719
Operating expenses					
Lease operating expenses	—	189,548	—	(12,414)	177,134
Midstream expenses	—	11,117	15,098	(8,626)	17,589
Well services expenses	—	37,228	—	—	37,228
Marketing, transportation and gathering expenses	—	61,571	—	(5,831)	55,740
Purchased oil and gas expenses	—	134,615	—	—	134,615
Production taxes	—	88,133	—	—	88,133
Depreciation, depletion and amortization	—	528,615	4,626	(2,439)	530,802
Exploration expenses	—	11,600	—	—	11,600
Impairment	—	6,887	—	—	6,887
General and administrative expenses	27,616	61,513	5,110	(2,442)	91,797
Total operating expenses	27,616	1,130,827	24,834	(31,752)	1,151,525
Gain on sale of properties	—	1,774	—	—	1,774
Operating income (loss)	(27,616)	138,563	34,987	(1,966)	143,968
Other income (expense)					
Equity in earnings of subsidiaries	323,953	29,352	—	(353,305)	—
Net loss on derivative instruments	—	(71,657)	—	—	(71,657)
Interest expense, net of capitalized interest	(131,329)	(15,489)	(19)	—	(146,837)
Other income (expense)	1	(1,333)	—	—	(1,332)
Total other income (expense), net	192,625	(59,127)	(19)	(353,305)	(219,826)
Income (loss) before income taxes	165,009	79,436	34,968	(355,271)	(75,858)
Income tax benefit (expense)	(41,213)	244,517	—	—	203,304
Net income including non-controlling interests	123,796	323,953	34,968	(355,271)	127,446
Less: Net income attributable to non-controlling interests	—	—	23,329	(19,679)	3,650
Net income attributable to Oasis	$ 123,796	$ 323,953	$ 11,639	$ (335,592)	$ 123,796

Condensed Consolidating Statement of Cash Flows

	Year Ended December 31, 2019				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
			(In thousands)		
Cash flows from operating activities:					
Net income (loss) including non-controlling interests	$ (128,243)	$ (13,898)	$ 215,231	$ (163,737)	$ (90,647)
Adjustments to reconcile net income (loss) including non-controlling interests to net cash provided by operating activities:					
Equity in (earnings) loss of subsidiaries	13,898	(167,848)	—	153,950	—
Depreciation, depletion and amortization	—	771,836	36,358	(21,002)	787,192
Gain on extinguishment of debt	(4,312)	—	—	—	(4,312)
Loss on sale of properties	—	4,455	—	—	4,455
Impairment	—	10,257	—	—	10,257
Deferred income taxes	(29,977)	(2,722)	—	—	(32,699)
Derivative instruments	—	106,314	—	—	106,314
Equity-based compensation expenses	13,933	19,296	378	—	33,607
Deferred financing costs amortization and other	16,898	9,419	946	—	27,263
Working capital and other changes:					
Change in accounts receivable, net	144,174	17,164	(37)	(147,572)	13,729
Change in inventory	—	(5,893)	—	—	(5,893)
Change in prepaid expenses	(177)	1,007	(505)	—	325
Change in accounts payable, interest payable and accrued liabilities	5,316	(96,526)	(3,311)	147,572	53,051
Change in other assets and liabilities, net	—	(11,692)	3,479	(1,576)	(9,789)
Net cash provided by operating activities	31,510	641,169	252,539	(32,365)	892,853
Cash flows from investing activities:					
Capital expenditures	—	(618,450)	(225,832)	(24,939)	(869,221)
Acquisitions	—	(21,009)	(24,939)	24,939	(21,009)
Proceeds from sale of properties	—	42,376	—	—	42,376
Derivative settlements	—	19,098	—	—	19,098
Net cash used in investing activities	—	(577,985)	(250,771)	—	(828,756)
Cash flows from financing activities:					
Proceeds from Revolving Credit Facilities	—	1,829,000	153,000	—	1,982,000
Principal payments on Revolving Credit Facilities	—	(1,960,000)	(12,500)	—	(1,972,500)
Repurchase of senior unsecured notes	(45,789)	(1)	—	—	(45,790)
Deferred financing costs	—	(79)	(973)	—	(1,052)
Purchases of treasury stock	(4,856)	—	—	—	(4,856)
Distributions to non-controlling interests	—	—	(95,771)	74,501	(21,270)
Investment in subsidiaries / capital contributions from parent	19,102	70,563	(47,529)	(42,136)	—
Payments on finance lease liabilities	—	(2,323)	(59)	—	(2,382)
Other	—	(1)	(417)	—	(418)
Net cash used in financing activities	(31,543)	(62,841)	(4,249)	32,365	(66,268)

Increase (decrease) in cash and cash equivalents	(33)	343	(2,481)	—	(2,171)
Cash and cash equivalents at beginning of period	179	15,362	6,649	—	22,190
Cash and cash equivalents at end of period	$ 146	$ 15,705	$ 4,168	$ —	$ 20,019

Condensed Consolidating Statement of Cash Flows

	Year Ended December 31, 2018				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
			(In thousands)		
Cash flows from operating activities:					
Net income (loss) including non-controlling interests	$ (35,296)	$ 103,586	$ 147,752	$ (235,542)	$ (19,500)
Adjustments to reconcile net income (loss) including non-controlling interests to net cash provided by (used in) operating activities:					
Equity in earnings of subsidiaries	(103,586)	(122,222)	—	225,808	—
Depreciation, depletion and amortization	—	623,349	28,409	(15,462)	636,296
Loss on extinguishment of debt	13,848	—	—	—	13,848
Gain on sale of properties	—	(28,587)	—	—	(28,587)
Impairment	—	384,228	—	—	384,228
Deferred income taxes	(36,102)	30,236	—	—	(5,866)
Derivative instruments	—	(28,457)	—	—	(28,457)
Equity-based compensation expenses	27,456	1,461	356	—	29,273
Deferred financing costs amortization and other	16,069	13,507	(519)	—	29,057
Working capital and other changes:					
Change in accounts receivable, net	(217,714)	(52,013)	3,194	243,025	(23,508)
Change in inventory	—	(14,324)	(22)	—	(14,346)
Change in prepaid expenses	(106)	(1,608)	(640)	—	(2,354)
Change in accounts payable, interest payable and accrued liabilities	6,886	234,441	27,814	(243,025)	26,116
Change in other assets and liabilities, net	—	221	—	—	221
Net cash provided by (used in) operating activities	(328,545)	1,143,818	206,344	(25,196)	996,421
Cash flows from investing activities:					
Capital expenditures	—	(865,935)	(283,026)	—	(1,148,961)
Acquisitions	—	(581,650)	—	—	(581,650)
Proceeds from sale of properties	—	333,229	—	—	333,229
Costs related to sale of properties	—	(2,850)	—	—	(2,850)
Derivative settlements	—	(213,528)	—	—	(213,528)
Other	—	224	—	—	224
Net cash used in investing activities	—	(1,330,510)	(283,026)	—	(1,613,536)
Cash flows from financing activities:					
Proceeds from Revolving Credit Facilities	—	2,949,000	275,000	—	3,224,000
Principal payments on Revolving Credit Facilities	—	(2,551,000)	(35,000)	—	(2,586,000)
Repurchase of senior unsecured notes	(423,340)	—	—	—	(423,340)
Proceeds from issuance of senior unsecured convertible notes	400,000	—	—	—	400,000
Deferred financing costs	(6,908)	(5,988)	(966)	—	(13,862)
Proceeds from issuance of Oasis Midstream common units, net of offering costs	—	—	44,503	—	44,503
Purchases of treasury stock	(6,846)	—	—	—	(6,846)
Distributions to non-controlling interests	—	—	(128,903)	114,789	(14,114)

Investment in subsidiaries / capital contributions from parent	365,602	(203,823)	(72,186)	(89,593)	—
Other	38	(1,794)	—	—	(1,756)
Net cash provided by financing activities	328,546	186,395	82,448	25,196	622,585
Increase (decrease) in cash and cash equivalents	1	(297)	5,766	—	5,470
Cash and cash equivalents at beginning of period	178	15,659	883	—	16,720
Cash and cash equivalents at end of period	$ 179	$ 15,362	$ 6,649	$ —	$ 22,190

Condensed Consolidating Statement of Cash Flows

	Year Ended December 31, 2017				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
			(In thousands)		
Cash flows from operating activities:					
Net income including non-controlling interests	$ 123,796	$ 323,953	$ 34,968	$ (355,271)	$ 127,446
Adjustments to reconcile net income including non-controlling interests to net cash provided by (used in) operating activities:					
Equity in earnings of subsidiaries	(323,953)	(29,352)	—	353,305	—
Depreciation, depletion and amortization	—	528,615	4,626	(2,439)	530,802
Gain on sale of properties	—	(1,774)	—	—	(1,774)
Impairment	—	6,887	—	—	6,887
Deferred income taxes	41,213	(244,097)	—	—	(202,884)
Derivative instruments	—	71,657	—	—	71,657
Equity-based compensation expenses	25,436	1,045	53	—	26,534
Deferred financing costs amortization and other	15,392	2,794	125	—	18,311
Working capital and other changes:					
Change in accounts receivable, net	(173,668)	(216,982)	(53,623)	277,887	(166,386)
Change in inventory	—	(2,501)	—	—	(2,501)
Change in prepaid expenses	9	(98)	(749)	—	(838)
Change in accounts payable, interest payable and accrued liabilities	7,074	337,319	56,601	(277,887)	123,107
Change in other assets and liabilities, net	—	(22,485)	—	—	(22,485)
Net cash provided by (used in) operating activities	(284,701)	754,981	42,001	(4,405)	507,876
Cash flows from investing activities:					
Capital expenditures	—	(594,945)	(52,404)	—	(647,349)
Acquisitions	—	(61,874)	(66,679)	66,679	(61,874)
Proceeds from sale of properties	—	72,453	—	(66,679)	5,774
Costs related to sale of properties	—	(366)	—	—	(366)
Derivative settlements	—	(8,264)	—	—	(8,264)
Other	—	(2,681)	—	—	(2,681)
Net cash used in investing activities	—	(595,677)	(119,083)	—	(714,760)
Cash flows from financing activities:					
Proceeds from Revolving Credit Facilities	—	1,084,000	78,000	—	1,162,000
Principal payments on Revolving Credit Facilities	—	(1,377,000)	—	—	(1,377,000)
Deferred financing costs	—	(577)	(2,137)	—	(2,714)
Proceeds from sale of common stock, net of offering costs	302,191	—	—	—	302,191
Proceeds from issuance of Oasis Midstream common units, net of offering costs	—	—	134,185	—	134,185
Purchases of treasury stock	(6,229)	—	—	—	(6,229)
Investment in subsidiaries / capital contributions from parent	(11,194)	138,872	(132,083)	4,405	—
Other	(55)	—	—	—	(55)

Net cash provided by (used in) financing activities	284,713	(154,705)	77,965	4,405	212,378
Increase in cash and cash equivalents	12	4,599	883	—	5,494
Cash and cash equivalents at beginning of period	166	11,060	—	—	11,226
Cash and cash equivalents at end of period	$ 178	$ 15,659	$ 883	$ —	$ 16,720

25. Supplemental Oil and Gas Disclosures — Unaudited

The supplemental data presented below reflects information for all of the Company's crude oil and natural gas producing activities.

Capitalized Costs

The following table sets forth the capitalized costs related to the Company's crude oil and natural gas producing activities:

	At December 31, 2019	At December 31, 2018
	(In thousands)	
Proved oil and gas properties[1]	$ 8,724,376	$ 7,878,104
Less: Accumulated depreciation, depletion, amortization and impairment	(3,601,019)	(2,853,353)
Proved oil and gas properties, net	5,123,357	5,024,751
Unproved oil and gas properties	738,662	1,034,085
Total oil and gas properties, net	$ 5,862,019	$ 6,058,836

(1) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $42.3 million and $40.5 million at December 31, 2019 and 2018, respectively.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

The following table sets forth costs incurred related to the Company's crude oil and natural gas activities for the periods presented:

	Year Ended December 31, 2019	2018	2017
	(In thousands)		
Acquisition costs:			
Proved oil and gas properties	$ —	$ 260,034	$ 61,874
Unproved oil and gas properties	23,058	696,293	5,424
Exploration costs	67,470	53,928	11,600
Development costs	542,133	923,562	511,905
Asset retirement costs	2,083	5,804	(2,965)
Total costs incurred	$ 634,744	$ 1,939,621	$ 587,838

Results of Operations for Crude Oil and Natural Gas Producing Activities

The following table sets forth the results of operations for crude oil and natural gas producing activities, which exclude straight-line depreciation, general and administrative expenses and interest expense, for the periods presented:

	Year Ended December 31, 2019	2018	2017
	(In thousands)		
Revenues	$ 1,408,771	$ 1,590,024	$ 1,034,634
Production costs	464,782	434,801	321,007
Depreciation, depletion and amortization	759,900	613,928	515,600
Exploration costs	6,658	27,432	11,600
Rig termination	384	—	—
Impairment	5,389	384,228	6,887
Income tax expense	40,745	30,770	67,148
Results of operations for crude oil and natural gas producing activities	$ 130,913	$ 98,865	$ 112,392

26. Supplemental Oil and Gas Reserve Information — Unaudited

The reserve estimates at December 31, 2019, 2018 and 2017 presented in the table below are based on reports prepared by DeGolyer and MacNaughton, the Company’s independent reserve engineers, in accordance with the FASB’s authoritative guidance on crude oil and natural gas reserve estimation and disclosures. At December 31, 2019, 2018 and 2017, all of the Company’s crude oil and natural gas producing activities were conducted within the continental United States.

The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil and gas reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made.

Estimated Quantities of Proved Crude Oil and Natural Gas Reserves — Unaudited

The following table sets forth the Company's estimated net proved, proved developed and proved undeveloped reserves at December 31, 2019, 2018 and 2017:

	Crude Oil (MBbl)	Natural Gas (MMcf)	MBoe[1]
2017			
Proved reserves			
Beginning balance	236,593	411,104	305,110
Revisions of previous estimates	(28,323)	54,726	(19,200)
Extensions, discoveries and other additions	36,238	89,489	51,153
Sales of reserves in place	(1,196)	(1,147)	(1,387)
Purchases of reserves in place	466	1,230	671
Production	(18,818)	(31,946)	(24,143)
Net proved reserves at December 31, 2017	224,960	523,456	312,204
Proved developed reserves, December 31, 2017	150,628	301,101	200,812
Proved undeveloped reserves, December 31, 2017	74,332	222,355	111,392
2018			
Proved reserves			
Beginning balance	224,960	523,456	312,204
Revisions of previous estimates	(17,352)	3,019	(16,850)
Extensions, discoveries and other additions	30,640	46,309	38,358
Sales of reserves in place	(12,470)	(20,735)	(15,926)
Purchases of reserves in place	25,688	43,107	32,873
Production	(23,050)	(42,430)	(30,122)
Net proved reserves at December 31, 2018	228,416	552,726	320,537
Proved developed reserves, December 31, 2018	144,533	339,444	201,107
Proved undeveloped reserves, December 31, 2018	83,883	213,282	119,430
2019			
Proved reserves			
Beginning balance	228,416	552,726	320,537
Revisions of previous estimates	(51,965)	(68,301)	(63,349)
Extensions, discoveries and other additions	49,297	87,382	63,861
Sales of reserves in place	(2,136)	(2,368)	(2,531)
Production	(22,825)	(55,906)	(32,142)
Net proved reserves at December 31, 2019	200,787	513,533	286,376
Proved developed reserves, December 31, 2019	113,418	314,000	165,751
Proved undeveloped reserves, December 31, 2019	87,369	199,533	120,625

(1) Natural gas is converted to barrel equivalents at the rate of six thousand cubic feet of natural gas to one barrel of oil.

Revisions of Previous Estimates

In 2019, the Company had net negative revisions of 63.3 MMBoe, or 20% of the beginning of the year estimated net proved reserves balance. These net negative revisions were attributable to negative revisions of 51.2 MMBoe due to well performance, 11.2 MMBoe due to lower realized prices and 7.6 MMBoe associated with alignment to the five-year development plan, offset by positive revisions of 6.7 MMBoe due to lower operating expenses. Proved developed revisions were primarily due to negative revisions of 30.2 MMBoe for performance largely related to higher than anticipated decline rates in recently developed spacing units and 9.6 MMBoe due to lower realized prices, partially offset by positive revisions of 5.1 MMBoe due to lower operating expenses. The proved undeveloped revisions were primarily due to negative revisions of 21.1 MMBoe for performance largely related to reductions in the anticipated hydrocarbon recoveries of proved areas during full field development due to changes in anticipated well densities and well performance and 7.0 MMBoe associated with alignment to the anticipated five-year development plan, offset by positive revisions of 1.7 MMBoe due to lower operating expenses.

In 2018, the Company had net negative revisions of 16.9 MMBoe, or 5% of the beginning of the year estimated net proved reserves balance. These 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 the five-year development plan, 14.4 MMBoe due to higher realized prices and 5.4 MMBoe for ownership adjustments. The proved developed net negative revisions of 20.2 MMBoe were primarily due to negative revisions of 33.0 MMBoe for performance revisions 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. The proved undeveloped revisions were primarily due to positive revisions of 14.7 MMBoe for the addition of PUDs that were previously removed from the 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.

In 2017, the Company had net negative revisions of 19.2 MMBoe, or 6% of the beginning of the year estimated net proved reserves balance.These net negative revisions were attributable to negative revisions of 39.1 MMBoe associated with 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. The proved developed negative revisions of 14.2 MMBoe 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. The proved undeveloped negative revisions of 5.0 MMBoe 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 1.8 MMBoe revisions 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.

Extensions, Discoveries and Other Additions

In 2019, the Company had a total of 63.9 MMBoe of additions due to extensions and discoveries. An estimated 10.3 MMBoe of these extensions and discoveries were associated with new producing wells at December 31, 2019, with 60% of these reserves from wells producing in the Bakken or Three Forks formations and 40% of reserves from wells producing in the Delaware Basin, respectively. An additional 53.6 MMBoe of proved undeveloped reserves were added in the Williston and Delaware Basins associated with the Company’s anticipated five-year development plan, with 63% of these proved undeveloped reserves in the Bakken or Three Forks formations in the Williston Basin and 37% of proved undeveloped reserves in the Delaware Basin.

In 2018, the Company had a total of 38.4 MMBoe of additions due to extensions and discoveries. An estimated 9.0 MMBoe of these extensions and discoveries were associated with new producing wells at December 31, 2018, with 77% of these reserves from wells producing in the Bakken or Three Forks formations and 23% of reserves from wells producing in the Delaware Basin, respectively. An additional 29.4 MMBoe of proved undeveloped reserves were added in the Williston and Delaware Basins associated with the Company’s anticipated five-year development plan, with 76% of these proved undeveloped reserves in the Bakken or Three Forks formations and 24% of proved undeveloped reserves in the Delaware Basin.

In 2017, the Company had a total of 51.2 MMBoe of additions due to extensions and discoveries. An estimated 17.9 MMBoe of these extensions and discoveries were associated with new producing wells at December 31, 2017, with 100% of these reserves from wells producing in the Bakken or Three Forks formations. An additional 33.3 MMBoe of proved undeveloped reserves were added in the Williston Basin associated with the Company’s 2017 operated and non-operated drilling program and anticipated five-year drilling plan, with 100% of these proved undeveloped reserves in the Bakken or Three Forks formations.

Sales of Reserves in Place

In 2019 and 2018, the Company divested 2.5 MMBoe and 15.9 MMBoe, respectively, of reserves associated with reservoirs in the Bakken or Three Forks formations (see Note 11—Divestitures). In 2017, the Company divested 1.4 MMBoe of reserves associated with reservoirs other than the Bakken or Three Forks formations.

Purchases of Reserves in Place

In 2019, there were no purchased estimated net proved reserves from acquisitions. In 2018, the Company purchased estimated net proved reserves of 32.9 MMBoe from acquisitions in the Delaware Basin (see Note 10—Acquisitions). In 2017, the Company purchased estimated net proved reserves of 0.7 MMBoe from acquisitions of additional working interests in its existing properties in the Williston Basin.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves — Unaudited

The Standardized Measure represents the present value of estimated future net cash flows from estimated net proved oil and natural gas reserves, less future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows. Production costs do not include DD&A of capitalized acquisition, exploration and development costs.

The Company's estimated net proved reserves and related future net revenues and Standardized Measure were determined using index prices for crude 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 were $55.85 per Bbl for crude oil and $2.62 per MMBtu for natural gas, $65.66 per Bbl for crude oil and $3.16 per MMBtu for natural gas and $51.34 per Bbl for crude oil and $2.99 per MMBtu for natural gas for the years ended December 31, 2019, 2018 and 2017, 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.

The following table sets forth the Standardized Measure of discounted future net cash flows from projected production of the Company's estimated net proved reserves at December 31, 2019, 2018 and 2017:

	At December 31,		
	2019	2018	2017
		(In thousands)	
Future cash inflows	$ 12,385,040	$ 16,652,405	$ 11,636,126
Future production costs	(5,509,127)	(6,609,097)	(4,458,418)
Future development costs	(1,490,521)	(1,701,672)	(992,271)
Future income tax expense	(188,823)	(968,466)	(580,481)
Future net cash flows	5,196,569	7,373,170	5,604,956
10% annual discount for estimated timing of cash flows	(2,352,200)	(3,322,864)	(2,304,261)
Standardized measure of discounted future net cash flows	$ 2,844,369	$ 4,050,306	$ 3,300,695

The following table sets forth the changes in the Standardized Measure of discounted future net cash flows applicable to estimated net proved reserves for the periods presented:

	2019	2018	2017
		(In thousands)	
January 1	$ 4,050,306	$ 3,300,695	$ 2,483,065
Net changes in prices and production costs	(1,070,192)	1,003,008	881,742
Net changes in future development costs	131,003	(89,304)	(60,929)
Sales of crude oil and natural gas, net	(943,989)	(1,155,223)	(769,367)
Extensions	437,700	461,196	661,467
Purchases of reserves in place	—	385,763	6,518
Sales of reserves in place	(36,907)	(197,867)	(9,024)
Revisions of previous quantity estimates	(732,253)	(115,015)	(78,942)
Previously estimated development costs incurred	246,311	303,364	157,386
Accretion of discount	467,426	368,374	262,776
Net change in income taxes	533,872	(240,908)	(238,354)
Changes in timing and other	(238,908)	26,223	4,357
December 31	$ 2,844,369	$ 4,050,306	$ 3,300,695

27. Quarterly Financial Data — Unaudited

The following tables set forth the Company's results of operations by quarter for the years ended December 31, 2019 and 2018:

	For the Year Ended December 31, 2019			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Total revenues	$ 575,732	$ 529,405	$ 482,743	$ 483,864
Operating income	50,444	71,572	8,441	23,966
Net income (loss) including non-controlling interests	(107,978)	51,174	30,311	(64,154)
Net income (loss) attributable to Oasis	(114,882)	42,757	20,288	(76,406)
Earnings (loss) attributable to Oasis per share:				
Basic	$ (0.37)	$ 0.14	$ 0.06	$ (0.24)
Diluted	$ (0.37)	$ 0.14	$ 0.06	$ (0.24)

	For the Year Ended December 31, 2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Total revenues	$ 473,812	$ 573,751	$ 674,629	$ 599,755
Operating income (loss)	112,985	(242,674)	179,045	69,656
Net income (loss) including non-controlling interests	3,712	(316,301)	66,223	226,866
Net income (loss) attributable to Oasis	590	(320,204)	62,341	221,977
Earnings (loss) attributable to Oasis per share:				
Basic	$ 0.00	$ (1.02)	$ 0.20	$ 0.71
Diluted	$ 0.00	$ (1.02)	$ 0.20	$ 0.70

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2020 Annual Meeting of Stockholders.

The Company's Code of Business Conduct and Ethics and the Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Controller (the "Code of Ethics") can be found on the Company's website located at http://www.oasispetroleum.com, under "Investor Relations — Corporate Governance." Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary.

If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver. We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K relating to amendments to or waivers from any provision of the Code of Ethics applicable to such persons by posting such information on our website.

Item 11. Executive Compensation

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2020 Annual Meeting of Stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2020 Annual Meeting of Stockholders.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2020 Annual Meeting of Stockholders.

Item 14. Principal Accountant Fees and Services

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2020 Annual Meeting of Stockholders.

PART IV

Item 15. Exhibits, Financial Statement Schedules

a. The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The following documents are included as exhibits to this report:

Exhibit No.	Description of Exhibit
3.1	Conformed version of Amended and Restated Certificate of Incorporation of Oasis Petroleum Inc., as amended by amendment filed on July 25, 2018 (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q on August 7, 2018, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Oasis Petroleum Inc. (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on February 28, 2019, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
4.2	Indenture dated as of February 2, 2011 among the Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on February 2, 2011, and incorporated herein by reference).
4.3	First Supplemental Indenture dated as of February 2, 2011 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on February 2, 2011, and incorporated herein by reference).
4.4	Second Supplemental Indenture dated as of September 19, 2011 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.4 to the Company's Registration Statement on Form S-4 on September 23, 2011, and incorporated herein by reference).
4.5	Indenture dated as of November 10, 2011 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on November 10, 2011, and incorporated herein by reference).
4.6	First Supplemental Indenture dated as of November 10, 2011 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on November 10, 2011, and incorporated herein by reference).
4.7	Second Supplemental Indenture dated as of July 2, 2012 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on July 2, 2012, and incorporated herein by reference).
4.8	Third Supplemental Indenture (to the Indenture dated as of February 2, 2011) dated as of June 18, 2013 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q on August 7, 2013, and incorporated herein by reference).
4.9	Third Supplemental Indenture (to the Indenture dated as of November 10, 2011) dated as of June 18, 2013 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q on August 7, 2013, and incorporated herein by reference).
4.10	Fourth Supplemental Indenture dated as of September 24, 2013 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on September 25, 2013, and incorporated herein by reference).
4.11	Fifth Supplemental Indenture (to the Indenture dated as of February 2, 2011) dated as of October 26, 2015 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on October 30, 2015, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
4.12	Fourth Supplemental Indenture (to the Indenture dated as of November 10, 2011) dated as of October 26, 2015 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed on October 30, 2015, and incorporated herein by reference).
4.13	Fifth Supplemental Indenture (to the Indenture dated as of November 10, 2011) dated as of October 26, 2015 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.3 to the Company's Current Report on Form 8-K filed on October 30, 2015, and incorporated herein by reference).
4.14	Sixth Supplemental Indenture (to the Indenture dated as of November 10, 2011) dated as of September 19, 2016 to Senior Indenture among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on September 19, 2016, and incorporated herein by reference).
4.15	Sixth Supplemental Indenture (to the Indenture dated as of February 2, 2011) dated as of October 25, 2017 among the Company, the Guarantors and U.S. Bank National Association, as trustee. (filed as Exhibit 4.15 to the Company's Annual Report on Form 10-K on February 28, 2018, and incorporated herein by reference).
4.16	Seventh Supplemental Indenture (to the Indenture dated as of November 10, 2011) dated as of October 25, 2017 among the Company, the Guarantors and U.S. Bank National Association, as trustee. (filed as Exhibit 4.16 to the Company's Annual Report on Form 10-K on February 28, 2018, and incorporated herein by reference).
4.17	Registration Rights Agreement, dated February 14, 2018, between the Oasis Petroleum Inc. and Forge Energy, LLC (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on February 16, 2018, and incorporated herein by reference).
4.18	Seventh Supplemental Indenture (to the Indenture dated as of February 2, 2011) dated as of April 27, 2018 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q on May 8, 2018, and incorporated herein by reference).
4.19	Eighth Supplemental Indenture (to the Indenture dated as of November 10, 2011) dated as of April 27, 2018 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q on May 8, 2018, and incorporated herein by reference).
4.20	Indenture, dated as of May 14, 2018, among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on May 18, 2018, and incorporated herein by reference).
4.21	Eighth Supplemental Indenture, dated as of May 14, 2018, among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on May 18, 2018, and incorporated herein by reference).
4.22	Ninth Supplemental Indenture, dated as of May 14, 2018, among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.3 to the Company's Current Report on Form 8-K on May 18, 2018, and incorporated herein by reference).
4.23(a)	Description of Registrant's Securities Registered Under Section 12 of the Exchange Act.
10.1	Second Amended and Restated Credit Agreement, dated as of April 5, 2013, among Oasis Petroleum Inc., as parent, Oasis Petroleum North America LLC, as borrower, the other credit parties party thereto, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 9, 2013, and incorporated herein by reference).
10.2	First Amendment to Second Amended and Restated Credit Agreement dated as of September 3, 2013 among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on September 5, 2013, and incorporated herein by reference).
10.3**	Form of Indemnification Agreement between Oasis Petroleum Inc. and each of the directors and executive officers thereof (filed as Exhibit 10.5 to the Company's Annual Report on Form 10-K on February 27, 2014, and incorporated herein by reference).
10.4**	Amended and Restated 2010 Annual Incentive Compensation Plan of Oasis Petroleum Inc. (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on August 6, 2014, and incorporated herein by reference).
10.5**	Form of Notice of Grant of Restricted Stock (filed as Exhibit 10.10 to the Company's Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
10.6**	Form of Restricted Stock Agreement (filed as Exhibit 10.11 to the Company’s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.7**	Form of Notice of Grant of Restricted Stock Unit (filed as Exhibit 10.12 to the Company’s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.8**	Form of Notice of Grant of Performance Share Units (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on August 3, 2012, and incorporated herein by reference).
10.9**	Form of Performance Share Unit Agreement (filed as Exhibit 10.2 to the Company’s Current Report on Form 8-K on August 3, 2012, and incorporated herein by reference).
10.10**	Amended and Restated Executive Change in Control and Severance Benefit Plan dated as of March 1, 2012 (filed as Exhibit 10.4 to the Company’s Current Report on Form 8-K on March 2, 2012, and incorporated herein by reference).
10.11	Second Amendment to Second Amended and Restated Credit Agreement dated as of September 30, 2014 among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on October 2, 2014, and incorporated herein by reference).
10.12	Letter Agreement dated as of March 4, 2015 between the Company and SPO Advisory Corp. (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on March 9, 2015, and incorporated herein by reference).
10.13**	Third Amended and Restated Employment Agreement effective as of March 20, 2015 between Oasis Petroleum Inc. and Thomas B. Nusz (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on March 20, 2015, and incorporated herein by reference).
10.14**	Fourth Amended and Restated Employment Agreement effective as of March 20, 2015 between Oasis Petroleum Inc. and Taylor L. Reid (filed as Exhibit 10.2 to the Company’s Current Report on Form 8-K on March 20, 2015, and incorporated herein by reference).
10.15**	Second Amended and Restated Employment Agreement effective as of March 20, 2015 between Oasis Petroleum Inc. and Michael H. Lou (filed as Exhibit 10.3 to the Company’s Current Report on Form 8-K on March 20, 2015, and incorporated herein by reference).
10.16**	Second Amended and Restated Employment Agreement effective as of March 20, 2015 between Oasis Petroleum Inc. and Nickolas J. Lorentzatos (filed as Exhibit 10.4 to the Company’s Current Report on Form 8-K on March 20, 2015, and incorporated herein by reference).
10.17	Third Amendment to Second Amended and Restated Credit Agreement dated as of April 13, 2015 among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties party thereto, Wells Fargo Bank, N.A., as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 14, 2015, and incorporated herein by reference).
10.18	Fourth Amendment to Second Amended and Restated Credit Agreement dated as of November 13, 2015 among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties party thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on November 18, 2015, and incorporated herein by reference).
10.19	Fifth Amendment to Second Amended and Restated Credit Agreement dated as of February 23, 2016 among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties party thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.35 to the Company’s Annual Report on Form 10-K on February 25, 2016, and incorporated herein by reference).
10.20**	Form of Notice of Grant of Performance Share Units (filed as Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q on May 10, 2016, and incorporated herein by reference).
10.21	Sixth Amendment to Second Amended and Restated Credit Agreement dated as of August 8, 2016 among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties party thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q on August 9, 2016, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
10.22	Seventh Amendment to Second Amended and Restated Credit Agreement dated as of October 14, 2016 among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties party thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on October 18, 2016, and incorporated herein by reference).
10.23	Eighth Amendment to Second Amended and Restated Credit Agreement, dated as of April 10, 2017, among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties party thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 13, 2017, and incorporated herein by reference).
10.24	Contribution Agreement, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, Oasis Petroleum LLC, OMS Holdings LLC, Oasis Midstream Services LLC, OMP GP LLC and OMP Operating LLC (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on September 29, 2017, and incorporated herein by reference).
10.25	Omnibus Agreement, dated as of September 25, 2017, by and among Oasis Midstream Partners LP, the Company, Oasis Petroleum LLC, OMS Holdings LLC, Oasis Midstream Services LLC, OMP GP LLC and OMP Operating LLC (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on September 29, 2017, and incorporated herein by reference).
10.26	Ninth Amendment to Second Amended and Restated Credit Agreement, dated as of September 25, 2017, by and among Oasis Petroleum North America LLC, as borrower, the guarantors party thereto, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on September 29, 2017, and incorporated herein by reference).
10.27	Services and Secondment Agreement, dated as of September 25, 2017, by and between Oasis Midstream Partners LP and the Company (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on September 29, 2017 and incorporated herein by reference).
10.28	Tenth Amendment to Second Amended and Restated Credit Agreement, dated as of November 7, 2017, by and among Oasis Petroleum North America LLC, as borrower, the guarantors party thereto, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (filed as Exhibit 10.5(a) to the Company's Quarterly Report on Form 10-Q on November 9, 2017 and incorporated herein by reference).
10.29	Eleventh Amendment to Second Amended and Restated Credit Agreement, dated as of February 26, 2018, by and among Oasis Petroleum North America LLC, as borrower, the guarantors party thereto, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on February 28, 2018 and incorporated herein by reference).
10.30	Twelfth Amendment to Second Amended and Restated Credit Agreement, dated as of April 19, 2018, by and among Oasis Petroleum North America LLC, as borrower, the guarantors party thereto, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on May 8, 2018, and incorporated herein by reference).
10.31**	Form of Restricted Stock Award Grant Notice (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on August 7, 2018, and incorporated herein by reference).
10.32**	Form of Restricted Stock Award Agreement (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q on August 7, 2018, and incorporated herein by reference).
10.33	Third Amended and Restated Credit Agreement, dated as of October 16, 2018, by and among Oasis Petroleum Inc., as parent, Oasis Petroleum North America LLC, as borrower, the other credit parties thereto, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 19, 2018, and incorporated herein by reference).
10.34	First Amendment to the Third Amended and Restated Credit Agreement, dated as of April 15, 2019, among Oasis Petroleum Inc., as parent, Oasis Petroleum North America LLC, as borrower, the other credit parties party thereto, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on May 8, 2019, and incorporated herein by reference).
10.35	Second Amendment to the Third Amended and Restated Credit Agreement, dated as of July 2, 2019, among Oasis Petroleum Inc., as parent, Oasis Petroleum North America LLC, as borrower, the other credit parties party thereto, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q on August 9, 2019, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
10.36	Third Amendment to the Third Amended and Restated Credit Agreement, dated as of November 4, 2019, among Oasis Petroleum Inc., as parent, Oasis Petroleum North America LLC, as borrower, the other credit parties party thereto, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on November 6, 2019, and incorporated herein by reference).
10.37**	Fourth Amended and Restated Employment Agreement effective as of March 20, 2018 between Oasis Petroleum Inc. and Thomas B. Nusz (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 22, 2018, and incorporated herein by reference).
10.38**	Fifth Amended and Restated Employment Agreement effective as of March 20, 2018 between Oasis Petroleum Inc. and Taylor L. Reid (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on March 22, 2018, and incorporated herein by reference).
10.39**	Third Amended and Restated Employment Agreement effective as of March 20, 2018 between Oasis Petroleum Inc. and Michael H. Lou (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on March 22, 2018, and incorporated herein by reference).
10.40**	Third Amended and Restated Employment Agreement effective as of March 20, 2018 between Oasis Petroleum Inc. and Nickolas J. Lorentzatos (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on March 22, 2018, and incorporated herein by reference).
10.41**	Amended and Restated 2010 Long Term Incentive Plan of Oasis Petroleum Inc. (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on May 4, 2018, and incorporated herein by reference).
10.42**	First Amendment to the Amended and Restated 2010 Long Term Incentive Plan of Oasis Petroleum Inc. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 3, 2019, and incorporated herein by reference).
10.43**	Form of Notice of Grant of Performance Share Units (filed as Exhibit 10.42 to the Company's Annual Report on Form 10-K on March 1, 2019, and incorporated herein by reference).
10.44**	Form of Phantom Unit Award Grant Notice (filed as Exhibit 10.43 to the Company's Annual Report on Form 10-K on March 1, 2019, and incorporated herein by reference).
10.45**	Form of Phantom Unit Award Agreement (filed as Exhibit 10.44 to the Company's Annual Report on Form 10-K on March 1, 2019, and incorporated herein by reference).
10.46**	Second Amendment to the Amended and Restated 2010 Long Term Incentive Plan of Oasis Petroleum Inc.
10.47**	Form of Notice of Grant of Performance Share Units.
21.1(a)	List of Subsidiaries of Oasis Petroleum Inc.
23.1(a)	Consent of PricewaterhouseCoopers LLP.
23.2(a)	Consent of DeGolyer and MacNaughton.
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
99.1	Report of DeGolyer and MacNaughton (filed as Exhibit 99.2 to the Company's Current Report on Form 8-K on January 30, 2020, and incorporated herein by reference).
101(a)	The following financial information from Oasis's Annual Report on Form 10-K for the year ended December 31, 2019, formatted in Inline XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Stockholders' Equity, (iv) Consolidated Statements of Cash Flows and (v) Notes to the Consolidated Financial Statements.
104(a)	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

(a) Filed herewith.
(b) Furnished herewith.
** Management contract or compensatory plan or arrangement.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on February 26, 2020.

OASIS PETROLEUM INC.

By: */s/ Thomas B. Nusz*
Thomas B. Nusz
Chairman of the Board and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated:

Signature	Title	Date
/s/ Thomas B. Nusz Thomas B. Nusz	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	February 26, 2020
/s/ Taylor L. Reid Taylor L. Reid	Director, President and Chief Operating Officer	February 26, 2020
/s/ Michael H. Lou Michael H. Lou	Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	February 26, 2020
/s/ William J. Cassidy William J. Cassidy	Director	February 26, 2020
/s/ John E. Hagale John E. Hagale	Director	February 26, 2020
/s/ Michael McShane Michael McShane	Director	February 26, 2020
/s/ Bobby S. Shackouls Bobby S. Shackouls	Director	February 26, 2020
/s/ Paula D. Polito Paula D. Polito	Director	February 26, 2020

GLOSSARY OF TERMS

The terms defined in this section are used throughout this Annual Report on Form 10-K:

"*Bbl*." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate, natural gas liquids or fresh water.

"*Bcf*." One billion cubic feet of natural gas.

"*Boe*." Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of crude oil.

"*British thermal unit*." The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"*Basin*." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"*Completion*." The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"*Developed acreage*." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"*Developed reserves*." Reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of required equipment is relatively minor when compared to the cost of a new well.

"*Development well*." A well drilled within the proved area of a natural gas or crude oil reservoir to the depth of a stratigraphic horizon known to be productive.

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

"*Economically producible*." A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

"*Environmental assessment*." An environmental assessment, a study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.

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

"*Field*." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"*Formation*." A layer of rock which has distinct characteristics that differ from nearby rock.

"*Horizontal drilling*." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"*MBbl*." One thousand barrels of crude oil, condensate, natural gas liquids or fresh water.

"*MBoe*." One thousand barrels of oil equivalent.

"*Mcf*." One thousand cubic feet of natural gas.

"*MMBbl*." One million barrels of crude oil, condensate, natural gas liquids or fresh water.

"*MMBoe*." One million barrels of oil equivalent.

"*MMBtu*." One million British thermal units.

"*MMcf*." One million cubic feet of natural gas.

"*NYMEX*." The New York Mercantile Exchange.

"*Net acres*." The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"Plug." A down-hole packer assembly used in a well to seal off or isolate a particular formation for testing, acidizing, cementing, etc.; also a type of plug used to seal off a well temporarily while the wellhead is removed.

"*PV-10*." When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Commission.

"*Productive well*." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"Proppant." Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

"*Proved developed reserves*." Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"*Proved reserves*." Those 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. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible crude oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, LKH, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil, HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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

"*Reasonable certainty*." If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

"*Recompletion*." The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"*Reserves*." Estimated remaining quantities of crude oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development prospects to known accumulations.

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

"Resource play." An expansive contiguous geographical area with known accumulations of crude oil or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and completion technologies.

"*Spacing*." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

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

"Unconventional resource." An umbrella term for crude oil and natural gas that is produced by means that do not meet the criteria for conventional production. What has qualified as "unconventional" at any particular time is a complex function of resource characteristics, the available E&P technologies, the economic environment, and the scale, frequency and duration of production from the resource. Perceptions of these factors inevitably change over time and often differ among users of the term. At present, the term is used in reference to crude oil and natural gas resources whose porosity, permeability, fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs. Coalbed methane, gas hydrates, shale gas, fractured reservoirs and tight gas sands are considered unconventional resources.

"*Unit*." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"Well stimulation." A treatment performed to restore or enhance the productivity of a well. Stimulation treatments fall into two main groups, hydraulic fracturing treatments and matrix treatments. Fracturing treatments are performed above the fracture pressure of the reservoir formation and create a highly conductive flow path between the reservoir and the wellbore. Matrix treatments are performed below the reservoir fracture pressure and generally are designed to restore the natural permeability of the reservoir following damage to the near-wellbore area. Stimulation in shale gas reservoirs typically takes the form of hydraulic fracturing treatments.

"*Wellbore*." The hole drilled by the bit that is equipped for crude oil or gas production on a completed well. Also called well or borehole.

"*Working interest*." The right granted to the lessee of a property to explore for and to produce and own crude oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"Workover." The repair or stimulation of an existing productive well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.

DESCRIPTION OF THE REGISTRANT'S SECURITIES

REGISTERED PURSUANT TO SECTION 12 OF THE

SECURITIES EXCHANGE ACT OF 1934

As of February 19, 2020, Oasis Petroleum Inc. has one class of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"): our common stock. For purposes of this description, references to "the Company," "we," "our" and "us" refer only to Oasis Petroleum Inc. and not to its subsidiaries.

DESCRIPTION OF CAPITAL STOCK

Authorized Capital Stock of Oasis Petroleum Inc.

The authorized capital stock of Oasis Petroleum Inc. consists of 900,000,000 shares of common stock, $0.01 par value per share, and 50,000,000 shares of preferred stock, $0.01 par value per share.

The following summary of our common stock, amended and restated certificate of incorporation, as amended (the "Amended Charter"), and amended and restated bylaws (the "Amended Bylaws") of Oasis Petroleum Inc. does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our Amended Charter and Amended Bylaws.

Common Stock

As of February 19, 2020, we had 323,926,171 shares of common stock outstanding, all of which is voting common stock.

Except as provided by law or in a preferred stock designation, holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, will have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, holders of common stock, as such, are not entitled to vote on any amendment to the Amended Charter (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to the Amended Charter (including any certificate of designations relating to any series of preferred stock) or pursuant to the General Corporation Law of the State of Delaware. Subject to preferences that may be applicable to any outstanding shares or series of preferred stock, holders of common stock are entitled to receive ratably such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors out of funds legally available for dividend payments. All outstanding shares of common stock are fully paid and non-assessable, and any shares of common stock sold pursuant to this prospectus will be fully paid and non-assessable. The holders of common stock have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to the common stock. In the event of any liquidation, dissolution or winding-up of our affairs, holders of common stock will be entitled to share ratably in our assets that are remaining after payment or provision for payment of all of our debts and obligations and after liquidation payments to holders of outstanding shares of preferred stock, if any.

Anti-Takeover Effects of Provisions of Our Amended Charter, Our Amended Bylaws and Delaware Law

Some provisions of Delaware law, and our Amended Charter and our Amended Bylaws described below, contain provisions that could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise; or removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions, summarized below, are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

We are subject to the provisions of Section 203 of the Delaware General Corporation Law, or DGCL, regulating corporate takeovers. In general, those provisions prohibit a Delaware corporation, including those whose securities are listed for trading on The Nasdaq Stock Market LLC ("Nasdaq"), from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the transaction is approved by the board of directors before the date the interested stockholder attained that status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced; or
- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

Section 203 defines "business combination" to include the following:

- any merger or consolidation involving the corporation and the interested stockholder;
- any sale, transfer, pledge or other disposition of 10% or more of the assets of the corporation involving the interested stockholder;
- subject to certain exceptions, any transaction that results in the issuance or transfer by the corporation of any stock of the corporation to the interested stockholder;
- any transaction involving the corporation that has the effect of increasing the proportionate share of the stock of any class or series of the corporation beneficially owned by the interested stockholder; or
- the receipt by the interested stockholder of the benefit of any loans, advances, guarantees, pledges or other financial benefits provided by or through the corporation.

In general, Section 203 defines an interested stockholder as any entity or person beneficially owning 15% or more of the outstanding voting stock of the corporation and any entity or person affiliated with or controlling or controlled by any of these entities or persons.

A Delaware corporation may "opt out" of Section 203 with an express provision in its original certificate of incorporation or an express provision in its certificate of incorporation or bylaws resulting from amendments approved by the holders of at least a majority of the corporation's outstanding voting shares. We did not "opt out" of the provisions of Section 203. The statute could prohibit or delay mergers or other takeover or change in control attempts and, accordingly, may discourage attempts to acquire us.

Amended Charter and Amended Bylaws

Among other things, our Amended Charter and Amended Bylaws:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our Amended Bylaws specify the requirements as to form and content of all stockholders' notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

- provide our board of directors the ability to authorize undesignated preferred stock. This ability makes it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deferring hostile takeovers or delaying changes in control or management of our company;
- provide that the authorized number of directors may be changed only by resolution of the board of directors;
- provide that all vacancies, including newly created directorships, may, except as otherwise required by law, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;
- provide that any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of preferred stock;
- provide that directors may be removed only for cause and only by the affirmative vote of holders of at least 80% of the voting power of our then outstanding common stock;
- provide our Amended Charter and Amended Bylaws may be amended by the affirmative vote of the holders of at least two-thirds of our then outstanding common stock;
- provide that special meetings of our stockholders may only be called by the board of directors, the chief executive officer or the chairman of the board;
- provide for our board of directors to be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, other than directors which may be elected by holders of preferred stock, if any. This system of electing and removing directors may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for stockholders to replace a majority of the directors;
- provide that we renounce any interest in the business opportunities of EnCap Investments, L.P. or any private fund that it manages or advises or any of its officers, directors, agents, stockholders, members, partners, affiliates and subsidiaries (other than our directors who are presented business opportunities in their capacity as our director) and that they have no obligation to offer us those opportunities; and
- provide that our Amended Bylaws can be amended or repealed at any regular or special meeting of stockholders or by the board of directors.

Limitation of Liability and Indemnification Matters

Our Amended Charter limits the liability of our directors for monetary damages for breach of their fiduciary duty as directors, except for liability that cannot be eliminated under the DGCL. Delaware law provides that directors of a company will not be personally liable for monetary damages for breach of their fiduciary duty as directors, except for liabilities:

- for any breach of their duty of loyalty to us or our stockholders;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;
- for unlawful payment of dividend or unlawful stock repurchase or redemption, as provided under Section 174 of the DGCL; or
- for any transaction from which the director derived an improper personal benefit.

Any amendment, repeal or modification of these provisions will be prospective only and would not affect any limitation on liability of a director for acts or omissions that occurred prior to any such amendment, repeal or modification.

Our Amended Charter and Amended Bylaws also provide that we will indemnify our directors and officers to the fullest extent permitted by Delaware law. Our Amended Charter and Amended Bylaws also permit us to purchase insurance on behalf of any officer, director, employee or other agent for any liability arising out of that person's actions as our officer, director, employee or agent, regardless of whether Delaware law would permit indemnification. We intend to enter into indemnification agreements with each of our current and future directors and officers. These agreements require us to indemnify these individuals to the fullest extent permitted under Delaware law against liability that may arise by reason of their service to us, and to advance expenses incurred as a result of any proceeding against them as to which they could be indemnified. We believe that the limitation of liability provision in our Amended Charter and the indemnification agreements will facilitate our ability to continue to attract and retain qualified individuals to serve as directors and officers.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is Computershare Trust Company, N.A.

Listing

Our common stock is listed on Nasdaq under the symbol "OAS."

SECOND AMENDMENT TO THE
OASIS PETROLEUM INC.
AMENDED AND RESTATED LONG TERM INCENTIVE PLAN

The Board of Directors of Oasis Petroleum Inc., a Delaware corporation (the "***Company***"), hereby makes this Second Amendment (the "***Second Amendment***") to the Oasis Petroleum Inc. Amended and Restated 2010 Long Term Incentive Plan (as amended, the "***Plan***") this 10th day of January, 2020.

WHEREAS, the Company established the Plan for purposes of providing incentive compensation awards to certain employees, officers, consultants and advisors of the Company and its subsidiaries which are generally based on the Company's common stock, par value $0.01 per share (the "***Stock***");

WHEREAS, the Plan currently restricts the withholding or surrendering of shares of Stock for tax purposes to the minimum statutory withholding rates; and

WHEREAS, the Board of Directors of the Company has determined that the Plan should be amended to allow income tax withholding for employees to occur at the highest withholding rates that may be utilized without creating adverse accounting treatment for the Company with respect to the applicable award.

NOW THEREFORE, for and in consideration of the foregoing and the agreements contained herein, the Plan shall be amended as follows:

1. *Amendment to Section 10(b)*. Section 10(b) of the Plan shall be amended and restated in its entirety as follows:

   The Company and any of its Subsidiaries are authorized to withhold from any Award granted, or any payment relating to an Award under this Plan, including from a distribution of Stock, amounts of withholding and other taxes due or potentially payable in connection with any transaction involving an Award, and to take such other action as the Committee may deem advisable to enable the Company and Participants to satisfy obligations for the payment of withholding taxes and other tax obligations relating to any Award. This authority shall include authority to withhold or receive Stock or other property and to make cash payments in respect thereof in satisfaction of a Participant's tax obligations, either on a mandatory or elective basis in the discretion of the Committee. Any determination made by the Committee to allow a Participant who is subject to Rule 16b-3 to pay taxes with shares of Stock through net settlement or previously owned shares shall be approved by either a committee made up of solely two or more Qualified Members or the full Board. If such tax withholding amounts are satisfied through net settlement or previously owned shares, the maximum number of shares of Stock that may be so withheld or surrendered shall be the number of shares of Stock that have an aggregate Fair Market Value on the date of withholding or surrender equal to the aggregate amount of such tax liabilities determined based on the greatest withholding rates for federal, state, foreign and/or local tax purposes, including payroll taxes, that may be utilized without creating adverse accounting treatment for the Company with respect to such Award, as determined by the Committee.

2. *Remainder of Plan*. Except as expressly provided herein, the Plan remains in full force and effect.

NOTICE OF GRANT OF PERFORMANCE SHARE UNITS

Pursuant to the terms and conditions of the Oasis Petroleum Inc. Amended and Restated 2010 Long Term Incentive Plan, as amended (the "***Plan***"), and the associated Performance Share Unit Agreement (the "***Agreement***"), you are hereby granted an award of Performance Share Units, whereby each Performance Share Unit that becomes earned, as determined by the Committee in its sole and absolute discretion, represents the right to receive one share of common stock of the Company, par value $0.01 per share ("***Stock***"), plus rights to certain Dividend Equivalents described in Section 3 of the Agreement, under the terms and conditions set forth below, in the Agreement, and in the Plan (the "***Performance Share Units***"). Capitalized terms used but not defined herein shall have the meanings set forth in the Plan or the Agreement.

Date of Grant: January 21, 2020 ("***Date of Grant***")

Number of Performance Share Units: The number of shares of Stock that may be deliverable in respect of this Award may range from 0% to 240% of the number of Performance Share Units awarded to you as shown on the Fidelity Stock Plan Services website (the "***Initial Performance Units***").

Performance Cycle: The Performance Cycle applicable to the Performance Share Units begins on January 21, 2020 and ends on:

(a) January 20, 2022 (24 months) for one third of the Initial Performance Units,
(b) January 20, 2023 (36 months) for one third of the Initial Performance Share Units, and
(c) January 20, 2024 (48 months) for the final third of the Initial Performance Share Units

(each such period, a "***Performance Cycle***" and the period from January 21, 2020 (the Date of Grant) to January 20, 2024, the "***Grant Cycle***").

Vesting Requirements: Your right to receive Stock in respect of Performance Share Units is generally contingent, in whole or in part, upon (a) except as otherwise provided below, your continuous active service with the Company through the end of the applicable Performance Cycle (the "***Continuous Service Requirement***"), and (b) the level of achievement of the TSR Vesting Objective as outlined below and in Appendix A, which summarizes the TSR Vesting Objective.

The "***TSR Vesting Objective***" means the Company's relative ranking in respect of the applicable Performance Cycle with regard to Total Shareholder Return (as defined in Appendix A) as compared to Total Shareholder Return of the Peer Companies (as defined in Appendix A). The level of achievement of the TSR Vesting Objective shall be determined in accordance with Appendix A. After the end of each applicable Performance Cycle, the Committee will determine the Company's Total Shareholder Return as compared to Total Shareholder Return of the Peer Companies and will certify the level of achievement with respect to the TSR Vesting Objective and what percentage of the Initial Performance Units eligible to vest for such Performance Cycle have been earned in accordance with the table set forth in Appendix A (such number of Performance Share Units that become earned shall hereinafter be called the "***Earned Performance Units***"), subject to your satisfaction of the Continuous Service Requirement.

Notwithstanding anything to the contrary herein, in the Agreement, in the Plan or in any other arrangement between you and the Company (including any employment agreement or the Amended and Restated Executive Change in Control and Severance Benefit Plan, if you participate in such plan):

(a) if a Change in Control occurs prior to the end of the Grant Cycle (the date of such occurrence, the "***Change in Control Date***") and you have remained in continuous service with the Company through the Change in Control Date, then, upon the occurrence of such Change in Control, with respect to any Initial Performance Units eligible to vest for a Performance Cycle that has not ended prior to the Change in Control Date, you shall be deemed to have earned a number of Performance Share Units equal to the number of Earned Performance Units you would have earned in accordance with Appendix A, but assuming that (i) each such Performance Cycle occurring during the Grant Cycle ended on the Change in Control Date, (ii) the determination of whether, and to what extent, the TSR Vesting Objective is achieved shall be based on actual performance against the stated criteria through the Change in Control Date, (iii) the Closing Value (as defined in Appendix A) for the Company is equal to the Change in Control Price instead of calculating the Closing Value in accordance with Appendix A, and (iv) the minimum percentage of Performance Share Units that may become Earned Performance Units for a Performance Cycle that has not ended prior to the Change in Control Date is 100%. For purposes of this Award, (A) "***Change in Control***" shall have the meaning given such term in the Plan; provided, that, in the event of any Business Combination following which both Thomas B. Nusz and Taylor L. Reid remain as Chief Executive Officer and President, respectively, and as members of the board of directors or similar governing body, of the entity resulting from such Business Combination (not including any subsidiary thereof), the Board of the pre-Business Combination Company may determine, **in its sole discretion, that no Change in Control has occurred for purposes of this Award; and (B) "*Change in Control Price*" shall equal the amount determined in the following clause (1), (2), (3), (4) or (5), whichever is applicable, as follows: (1) the price per share offered to holders of Stock in any merger or consolidation, (2) the per share Fair Market Value of the Stock immediately before the Change in Control, without regard to assets sold in the Change in Control and assuming the Company has received the consideration paid for the assets in the case of a sale of assets, (3) the amount distributed per share of Stock in a dissolution transaction, (4) the price per share offered to holders of Stock in any tender offer or exchange offer whereby a Change in Control takes place, or (5) if such Change in Control occurs other than pursuant to a transaction described in clauses (1), (2), (3), or (4), the volume weighted average of the Company's Stock price on each trading day in the 30-day period preceding the Change in Control Date**.

(b) if your employment or service relationship with the Company or any of its Subsidiaries is terminated due to your death or Disability prior to the end of the Grant Cycle, then you shall be deemed to have earned, with respect to any Initial Performance Units eligible to vest for a Performance Cycle that has not ended prior to your termination date, a number of Performance Share Units equal to 200% of the Initial Performance Units eligible to vest with respect to such Performance Cycle. For purposes of this Award, "***Disability***" shall have the meaning given such term in any employment agreement between you and the Company; provided, however, that if there is no existing employment agreement between you and the Company, the term "Disability" shall mean your inability to perform the essential functions of your position with or without reasonable accommodation, if required by law, due to physical or mental impairment. The existence of any such Disability shall be certified, at the Company's discretion, by either the Company's disability carrier or a physician acceptable to both you and the Company. If the parties are not able to agree on the choice of physician, each party shall select a physician who, in turn, shall select a third physician to render such certification. In no event will your employment be terminated as a result of Disability, unless otherwise agreed to by you and the Company, until at least 180 consecutive days of leave have elapsed and the Company has provided you with written notice of termination.

(c) if your employment or service relationship with the Company or any of its Subsidiaries is terminated prior to the end of the Grant Cycle by the Company or a Subsidiary without "***Cause***" or by you for "***Good Reason***" (in each case, as such terms are defined in any employment agreement between you and the Company or in the Amended and Restated Executive Change in Control and Severance Benefit Plan, if you participate in such plan), then you shall be deemed to have earned, with respect to any Initial Performance Units eligible to vest for a Performance Cycle that has not ended prior to your termination date, the number of Earned Performance Units that you would have actually earned in accordance with Appendix A as of the end of each such Performance Cycle had you remained employed through the end of the Performance Cycle.

Any of your Performance Share Units that are eligible to be earned but that do not become Earned Performance Units as of the end of the applicable Performance Cycle shall terminate and be cancelled upon the expiration of such Performance Cycle.

Date of Settlement: Payment in respect of Earned Performance Units shall be made no later than March 15 of the calendar year following the calendar year in which the last day of the applicable Performance Cycle occurs, except that (a) in the event of your death or Disability, payments in respect of Earned Performance Units shall be made no later than the 30th day following your death or termination for Disability; and (b) in the event of a Change in Control, payments in respect of Earned Performance Units shall be made no later than five (5) business days after the Change in Control Date (in each case, the "***Date of Settlement***").

All payments with respect to Earned Performance Units shall be made in freely transferable shares of Stock, and will be subject to all applicable tax withholding requirements.

Upon full settlement of the Performance Share Units hereunder and pursuant to Section 3 of the Agreement, no additional payments will be made pursuant to this Award and the Award shall terminate.

By your acceptance of this document, you and the Company hereby acknowledge receipt of the Performance Share Units issued on the Date of Grant indicated above, which have been granted under the terms and conditions contained herein and in the Plan and the Agreement. Alternatively, you acknowledge your agreement to be bound to the terms of this Notice, the Agreement and the Plan in connection with your acceptance of the Performance Share Units issued hereby through procedures, including electronic procedures, provided by or on behalf of the Company.

You acknowledge and agree that (a) you are not relying upon any written or oral statement or representation of the Company, its affiliates, or any of their respective employees, directors, officers, attorneys or agents (collectively, the "***Company Parties***") regarding the tax effects associated with your execution of this Notice of Grant of Performance Share Units and your receipt and holding of and the vesting of the Performance Share Units, and (b) in deciding to enter into this Agreement, you are relying on your own judgment and the judgment of the professionals of your choice with whom you have consulted. You hereby release, acquit and forever discharge the Company Parties from all actions, causes of actions, suits, debts, obligations, liabilities, claims, damages, losses, costs and expenses of any nature whatsoever, known or unknown, on account of, arising out of, or in any way related to the tax effects associated with your execution of the Agreement and your receipt and holding of and the vesting of the Performance Share Units.

You further acknowledge receipt of a copy of the Plan and the Agreement and agree to all of the terms and conditions of the Plan and the Agreement, which are incorporated herein by reference.

OASIS PETROLEUM INC.,
a Delaware corporation

By:________________________________
Name:_____________________________
Title:______________________________

Attachment: Appendix A – Total Shareholder Return Vesting Objective

Appendix A

Total Shareholder Return Vesting Objective

The TSR Vesting Objective for the Performance Share Units is outlined in this Appendix A below. The "***TSR Vesting Objective***" means the Company's relative ranking in respect of the applicable Performance Cycle with regard to Total Shareholder Return as compared to the Total Shareholder Return of the Peer Companies. The Committee shall have the sole discretion for determining the level of achievement with respect to the TSR Vesting Objective and the number of Earned Performance Units for each Performance Cycle and any such determinations shall be conclusive.

1. Defined Terms.

(a) "***Total Shareholder Return***" or "***TSR***" means, as to the Company and each of the Peer Companies, the annualized rate of return shareholders receive through stock price changes and the assumed reinvestment of dividends paid over the applicable Performance Cycle. Dividends per share paid other than in the form of cash shall have a value equal to the amount of such dividends reported by the issuer to its shareholders for purposes of Federal income taxation. For purposes of determining the Total Shareholder Return for the Company and each of the Peer Companies, the change in the price of the Company's Stock and of the common stock of each Peer Company, as the case may be, shall be based upon the volume weighted average of the stock prices of the Company and each such Peer Company on each trading day in the 30-day period preceding each of the start (the "***Initial Value***") and the end (the "***Closing Value***") of the applicable Performance Cycle. The Initial Value of the Stock to be used to determine Total Shareholder Return over each Performance Cycle is [**$______**].

(b) "***Peer Company***" means a company that is listed below.

• Antero Resources Corporation
• Cabot Oil & Gas Corporation
• Callon Petroleum Company
• Centennial Resource Development
• Cimarex Energy Co.
• Matador Resources Company
• PDC Energy, Inc.
• QEP Resources Inc.
• Range Resources Corporation
• SM Energy Co.
• Whiting Petroleum Corporation
• WPX Energy, Inc.
• Parsley Energy, Inc.

In addition, (i) the Standard & Poor's Oil & Gas Exploration & Production Select Industry Index, (ii) the Standard & Poor's 500 Index; (iii) the Russell 2000 Index; (iv) the Standard & Poor's MidCap 400 Index; and (v) the Standard & Poor's SmallCap 600 Index, each index to be weighted as a single company, shall also be included as a Peer Company.

If, prior to the end of any Performance Cycle, a company listed above ceases to have a class of common equity securities listed to trade on a national securities exchange which is registered with the Commission under Section 6 of the Exchange Act (a "national securities exchange"), then for purposes of determining the Total Shareholder Return for such Peer Company for the

Performance Cycle in which such company ceases to have a class of common equity securities listed to trade on a national securities exchange, the change in the price of the Peer Company's common stock shall be based upon the volume weighted average of the stock price of such Peer Company on each trading day in the 30-day period preceding the start of the applicable Performance Cycle (the "***Initial Value***") and (i) if, following the cessation of trading on a national securities exchange, such Peer Company's class of common equity securities is publicly traded on another market, exchange or quotation system, the volume weighted average of the stock price, on whatever market, exchange or quotation system on which the Peer Company's common equity securities is publicly traded, of such Peer Company on each trading day in the 30-day period preceding the end of the applicable Performance Cycle (the "***Closing Value***") or (ii) if, following the cessation of trading on a national securities exchange, such Peer Company's class of common equity securities is not publicly traded on another market, exchange or quotation system, the stock price of the Peer Company on the last day during the Performance Cycle that such Peer Company had a class of common equity securities which was publicly traded on another market, exchange or quotation system (the "***Closing Value***"). Following the end of any Performance Cycle in which such company ceases to have a class of common equity securities listed to trade on a national securities exchange, such company shall not be a Peer Company for purposes of calculating the Company's TSR Vesting Objective under this Appendix A for any other Performance Cycle which has not ended previously within the Grant Cycle.

If, prior to the end of any Performance Cycle, a company listed above is acquired or merged and, thus, ceases to have a class of common equity securities listed to trade on a national securities exchange or publicly traded on another market, exchange or quotation system, then for purposes of determining the Total Shareholder Return for such Peer Company for the Performance Cycle in which such company is so acquired or merged, the change in the price of the Peer Company's common stock shall be based upon the volume weighted average of the stock price of such Peer Company on each trading day in the 30-day period preceding the start of the applicable Performance Cycle (the "***Initial Value***") and the stock price on the last day during the Performance Cycle that such Peer Company had a class of common equity securities listed to trade on a national securities exchange or publicly traded on another market, exchange or quotation system before the closing of the merger or acquisition (the "***Closing Value***"). Following the end of any Performance Cycle in which such company ceases to have a class of common equity securities listed to trade on a national securities exchange due to an acquisition or merger, such company shall not be a Peer Company for purposes of calculating the Company's TSR Vesting Objective under this Appendix A for any other Performance Cycle which has not ended previously within the Grant Cycle.

2. Calculation of Ranking; Earned Performance Units.

(a) After the end of each Performance Cycle, the Committee will:

(i) calculate the Company's Total Shareholder Return and the Total Shareholder Return of each Peer Company;

(ii) rank, from highest to lowest, the Total Shareholder Return of the Company and each Peer Company;

(iii) calculate the percentage of Initial Performance Units that will become Earned Performance Units for each corresponding TSR rank, where (i) 200% Initial Performance Units become Earned Performance

Units if the Company TSR Rank is 1, (ii) 0% Initial Performance Units become Earned if the Company TSR rank is in the bottom three, and (iii) the percentage of Initial Performance Units that become Earned corresponding to the remaining TSR rankings will be determined by distributing linearly between the highest and lowest ranking percentages between 200% and 0%, provided that the percentage of Initial Performance Units that become Earned corresponding to two rankings above the lowest ranking will be reduced to 0%; and

(iv) certify the level of achievement with respect to the TSR Vesting Objective and determine the number of Earned Performance Units for the Performance Cycle.

The following table is provided as an example of the above determination, which depends on the number of Peer Companies remaining at the end of the Performance Cycle:

Total Shareholder Return Rank (TSR Vesting Objective)	**% of Initial Performance Units eligible to vest for the Performance Cycle that will become Earned Performance Units**	**% of Initial Performance Units eligible to vest for the Performance Cycle that will become Earned Performance Units**	**% of Initial Performance Units eligible to vest for the Performance Cycle that will become Earned Performance Units**
1	200%	200%	200%
2	188%	188%	187%
3	176%	175%	173%
4	165%	163%	160%
5	153%	150%	147%
6	141%	138%	133%
7	129%	125%	120%
8	118%	113%	107%
9	106%	100%	93%
10	94%	88%	80%
11	82%	75%	67%
12	71%	63%	53%
13	59%	50%	40%
14	47%	38%	0%
15	35%	0%	0%
16	0%	0%	0%
17	0%	0%	
18	0%		

(b) IRR Multiplier Provisions. Notwithstanding anything in Section 2(a), the Initial Performance Units shall be subject to further adjustment based solely on the Company's IRR for a Performance Cycle, as follows:

(i) no Initial Performance Units will become Earned Performance Units for a Performance Cycle in the event that the Company's IRR for the period is negative;

(ii) in the event that the Company's IRR for a Performance Cycle is positive, but less than 8%, the target percentage achieved during the calculations in Section 2(a) above with respect to the Initial Performance Units shall be further multiplied by a percentage between 50% and 100%, which shall be calculated as follows:

[(100%-50%)/8] x [IRR%] +50%

(iii) in the event that the Company's IRR for a Performance Cycle is equal to or greater than 8% but less than 15%, the target percentage achieved during the calculations in Section 2(a) above with respect to the Initial Performance Units shall be further multiplied by a percentage between 100% and 120%, which shall be calculated as follows: and

[(120%-100%)/7] x [IRR%-8%] +100%

(iv) in the event that the Company's IRR for a Performance Cycle is equal to or greater than 15%, the target percentage achieved during the calculations in Section 2(a) above with respect to the Initial Performance Units shall be further multiplied by 120%.

As an example of this Section 2(b), using a scenario where there are 18 Peer Companies and the Company's rank is 8, the percentage of Initial Performance Units that would be earned pursuant to Section 2(a) would be 118%. If the Company's IRR is negative, no Initial Performance Units will become Earned Performance Units. If the Company's IRR equals 3% then only 68.75% of 118% (or 81.13%) of Initial Performance Units will become Earned Performance Units pursuant to the following calculation:

[(100%-50%)/8] x [3%] +50% = 68.75% IRR Multiplier

If the Company's IRR equals 11%, then 108.57% of 118% (or 128.11%) of Initial Performance Units will become Earned Performance Units pursuant to the following calculation:

[(120%-100%)/7] x [3%] +100% = 108.57% IRR Multiplier

Finally, if the Company's IRR is 20%, then 120% of 118% (or 141.6%) of Initial Performance Units will become Earned Performance Units.

(c) Notwithstanding the foregoing:

(i) if the Company's Initial Value is greater than its Closing Value for any Performance Cycle, the greatest percentage of Performance Share

Units that may become Earned Performance Units for that Performance Cycle is 100%;

(ii) if the per share Fair Market Value of the Stock on the last day of the applicable Performance Cycle is greater than the Maximum Price (as defined below), the number of Performance Share Units that will become Earned Performance Units will be equal to the number of Performance Share Units that would otherwise become Earned Performance Units pursuant to this Appendix A multiplied by a fraction, the numerator of which is the Maximum Price and the denominator of which is the Fair Market Value of the stock on the last day of the applicable Performance Cycle; the "**Maximum Price**" shall be as follows:

A. For the Performance Cycle ending in 2022: $8
B. For the Performance Cycle ending in 2023: $9
C. For the Performance Cycle ending in 2024: $10

(iii) no Performance Share Units will become Earned Performance Units for a Performance Cycle unless you also satisfy the applicable Continuous Service Requirement in accordance with the terms of the Agreement and the Notice of Grant; and

(iv) the Company will have all interpretation powers provided to it within the Plan in making calculations, interpretations or decisions regarding this Award.

Exhibit 21.1

List of Subsidiaries of Oasis Petroleum Inc.

Name of Subsidiary	Jurisdiction of Incorporation or Organization
Oasis Petroleum LLC	Delaware
Oasis Petroleum North America LLC	Delaware
Oasis Petroleum Permian LLC	Delaware
Oasis Petroleum Marketing LLC	Delaware
Oasis Well Services LLC	Delaware
Oasis Midstream Services LLC	Delaware
OMS Holdings LLC	Delaware
OMP GP LLC	Delaware
Oasis Midstream Partners LP	Delaware
OMP Operating LLC	Delaware
Bobcat DevCo LLC	Delaware
Beartooth DevCo LLC	Delaware
Bighorn DevCo LLC	Delaware
Panther DevCo LLC	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-219302) and Form S-8 (No. 333-167664, No. 333-206025, No. 333-213118, No. 333-227021 and No. 333-236423) of Oasis Petroleum Inc. of our report dated February 26, 2020 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 26, 2020

Exhibit 23.2

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

February 26, 2020

Oasis Petroleum Inc.
1001 Fannin Street, Suite 1500
Houston, Texas 77002

Ladies and Gentlemen:

We hereby consent to the reference to DeGolyer and MacNaughton and to the incorporation of the estimates contained in our report entitled "Report as of December 31, 2019 on Reserves and Revenue of Certain Properties with interests attributable to Oasis Petroleum Inc." (our Report) in Part 1 and in the "Notes to Consolidated Financial Statements" portion of the Annual Report on Form 10-K of Oasis Petroleum Inc. for the year ended December 31, 2019 (the Annual Report). We further consent to the incorporation of estimates contained in our reports entitled "Report as of December 31, 2018 on Reserves and Revenue of Certain Properties with interests attributable to Oasis Petroleum Inc." and "Report as of December 31, 2017 on Reserves and Revenue of Certain Properties owned by Oasis Petroleum Inc." In addition, we hereby consent to the incorporation by reference of our Report of Third Party dated January 20, 2020, in the "Exhibits, Financial Statement Schedules" portion of the Annual Report. We further consent to the incorporation by reference of references to DeGolyer and MacNaughton and to our Report in Oasis Petroleum Inc.'s Registration Statements on Form S-3 (File No. 333-219302) and Form S-8 (File No. 333-167664, File No. 333-206025, File No. 333-213118, File No. 333-227021 and File No. 333-236423).

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Thomas B. Nusz, certify that:

1. I have reviewed this annual report on Form 10-K of Oasis Petroleum Inc. (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 26, 2020

/s/ Thomas B. Nusz

Thomas B. Nusz
Chairman and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Michael H. Lou, certify that:

1. I have reviewed this annual report on Form 10-K of Oasis Petroleum Inc. (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 26, 2020

/s/ Michael H. Lou

Michael H. Lou
Executive Vice President and Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Oasis Petroleum Inc. (the “Company”) on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Thomas B. Nusz, Chairman and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2020

/s/ Thomas B. Nusz

Thomas B. Nusz
Chairman and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 32.2

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Oasis Petroleum Inc. (the “Company”) on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Michael H. Lou, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2020

/s/ Michael H. Lou

Michael H. Lou
Executive Vice President and Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)