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

FORM 10-K

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

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

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

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

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

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

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

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

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

Large accelerated filer ý Accelerated filer ¨

Non-accelerated filer ¨ Smaller reporting company ¨

Emerging growth company ¨

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

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

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

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

Documents Incorporated By Reference:

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

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

Forward-looking statements may include statements about:

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

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

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

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PART I

Item 1. Business

Overview

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

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

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

Our business

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

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

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

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

Our competitive strengths

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

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

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

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

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

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

Our operations - exploration and production activities

Proved reserves

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

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

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

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

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

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

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

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

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

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

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

Reconciliation of Standardized Measure to PV-10

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

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

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

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

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Proved undeveloped reserves

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

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

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

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

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

Independent petroleum engineers

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

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

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Technology used to establish proved reserves

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

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

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

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

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

Internal controls over reserves estimation process

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

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

- Comparison of historical expenses from the lease operating statements and workover authorizations for expenditure to the operating costs input in our reserves database;
- Review of working interests and net revenue interests in our reserves database against our well ownership system;
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- Review of historical realized prices and differentials from index prices as compared to the differentials used in our reserves database;
- Review of updated capital costs prepared by our operations team;
- Review of internal reserve estimates by well and by area by our internal reservoir engineers;
- Discussion of material reserve variances among our internal reservoir engineers and our Senior Vice President of Asset Management and Chief Engineer;

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

Production, revenues, price and cost history

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

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

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

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

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

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

(4)

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

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

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

Productive wells

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

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

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

Acreage

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

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

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

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Undeveloped acreage

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

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

Drilling and completion activity

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

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