EOG RESOURCES INC
Form 10-K
February 26, 2019

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
or
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 1-9743

EOG RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Delaware	47-0684736
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1111 Bagby, Sky Lobby 2, Houston, Texas 77002
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: 713-651-7000

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o 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 o

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 o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the 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. o

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

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. o

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

State the 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. Common Stock aggregate market value held by non-affiliates as of June 30, 2018: $71,861 million.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. Class: Common Stock, par value $0.01 per share, 580,053,225 shares outstanding as of February 15, 2019.

Documents incorporated by reference. Portions of the Definitive Proxy Statement for the registrant's 2019 Annual Meeting of Stockholders, to be filed within 120 days after December 31, 2018, are incorporated by reference into Part III of this report.

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PART I

ITEM 1. Business

General

EOG Resources, Inc., a Delaware corporation organized in 1985, together with its subsidiaries (collectively, EOG), explores for, develops, produces and markets crude oil and natural gas primarily in major producing basins in the United States of America (United States or U.S.), The Republic of Trinidad and Tobago (Trinidad), The People's Republic of China (China), Canada and, from time to time, select other international areas. EOG's principal producing areas are further described in "Exploration and Production" below. EOG's Annual Reports on Form 10-K, Quarterly Reports on Form 10 Q, Current Reports on Form 8-K and any amendments to those reports (including related exhibits and supplemental schedules, filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act) are made available, free of charge, through EOG's website, as soon as reasonably practicable after such reports have been filed with, or furnished to, the United States Securities and Exchange Commission (SEC). EOG's website address is www.eogresources.com. Information on our website is not incorporated by reference into, and does not constitute a part of, this report.

At December 31, 2018, EOG's total estimated net proved reserves were 2,928 million barrels of oil equivalent (MMBoe), of which 1,532 million barrels (MMBbl) were crude oil and condensate reserves, 614 MMBbl were natural gas liquids (NGLs) reserves and 4,687 billion cubic feet (Bcf), or 782 MMBoe, were natural gas reserves (see "Supplemental Information to Consolidated Financial Statements"). At such date, approximately 98% of EOG's net proved reserves, on a crude oil equivalent basis, were located in the United States, 1% in Trinidad and 1% in other international areas. Crude oil equivalent volumes are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet (Mcf) of natural gas.

As of December 31, 2018, EOG employed approximately 2,800 persons, including foreign national employees.

EOG's operations are all crude oil and natural gas exploration and production related. For information regarding the risks associated with EOG's domestic and foreign operations, see ITEM 1A, Risk Factors.

EOG's business strategy is to maximize the rate of return on investment of capital by controlling operating and capital costs and maximizing reserve recoveries. Pursuant to this strategy, each prospective drilling location is evaluated by its estimated rate of return. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis, allowing EOG to deliver long-term production growth while maintaining a strong balance sheet. EOG is focused on cost-effective utilization of advanced technology associated with three-dimensional seismic and microseismic data, the development of reservoir simulation models, the use of improved drilling equipment, completion technologies for horizontal drilling and formation evaluation. These advanced technologies are used, as appropriate, throughout EOG to reduce the risks and costs associated with all aspects of oil and gas exploration, development and exploitation. EOG implements its strategy primarily by emphasizing the drilling of internally generated prospects in order to find and develop low-cost reserves. Maintaining the lowest possible operating cost structure that is consistent with efficient, safe and environmentally responsible operations is also an important goal in the implementation of EOG's strategy.

With respect to information on EOG's working interest in wells or acreage, "net" oil and gas wells or acreage are determined by multiplying "gross" oil and gas wells or acreage by EOG's working interest in the wells or acreage.

Exploration and Production

United States Operations

EOG's operations are located in most of the productive basins in the United States with a focus on crude oil and, to a lesser extent, liquids-rich natural gas plays.

At December 31, 2018, on a crude oil equivalent basis, 53% of EOG's net proved reserves in the United States were crude oil and condensate, 21% were NGLs and 26% were natural gas. The majority of these reserves are in long-lived fields with well-established production characteristics. EOG believes that opportunities exist to increase production through continued development in and around many of these fields and through the utilization of applicable technologies. EOG also maintains an active exploration program designed to extend fields and add new trends and resource plays to its already broad portfolio.

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The following is a summary of significant developments during 2018 and certain 2019 plans for EOG's United States operations.

	2018					2019
Area of Operation	Crude Oil & Condensate Volumes (MBbld) (1)	Natural Gas Liquids Volumes (MBbld) (1)	Natural Gas Volumes (MMcfd) (1)	Total Net Acres (2)	Net Well Completions	Expected Net Well Completions
Eagle Ford	171	31	159	579,000	304	300
Austin Chalk	20	7	42	— (3)	27	15
Permian Basin	132	46	338	913,000	265	275
Rocky Mountain Area	62	15	207	1,232,000	109	95
Upper Gulf Coast	1	—	4	441,000	1	5
Mid-Continent	6	2	12	125,000	31	35
Fort Worth Basin	2	14	78	152,000	—	—
South Texas	1	1	24	391,000	8	5
Marcellus Shale	—	—	59	172,000	15	—

(1) Thousand barrels per day or million cubic feet per day, as applicable.
(2) Total net acres excludes approximately 0.3 million net acres related to other areas.
(3) The Austin Chalk play encompasses the same net acres as the Eagle Ford.

The Eagle Ford continues to prove itself as a world-class crude oil field having produced in excess of 2.9 billion barrels of crude oil and condensate. With approximately 516,000 of its 579,000 total net acres in the prolific oil window, EOG continues to be the largest crude oil producer in the Eagle Ford with cumulative gross production in excess of 490 MMBbl of crude oil and condensate. In 2018, EOG completed 304 net Eagle Ford wells and continued to test the Austin Chalk play concept with the completion of 27 net Austin Chalk wells. EOG is still evaluating the extent of prospectivity of the Austin Chalk, which overlays the Eagle Ford. EOG also continued its enhanced oil recovery (EOR) gas injection program in 2018, adding 54 wells to the program. EOG does not expect to add wells to the EOR program in 2019 while it evaluates additional primary development opportunities. EOG expects to complete approximately 300 net Eagle Ford wells and 15 net Austin Chalk wells in 2019 while continuing to improve well productivity and operational efficiencies. The combination of exceptional execution and continuous operational improvements have made this play one of the foundations of EOG's portfolio.

In the Permian Basin, EOG completed 265 net wells during 2018, primarily in the Delaware Basin Wolfcamp Shale, Bone Spring and Leonard plays. EOG continued to consolidate its acreage position in each of these world-class assets through small leasing transactions and the exchange of acreage with other nearby operators. EOG has approximately 346,000 net acres in the Delaware Basin Wolfcamp Shale play where it completed 219 net wells in 2018. The success of the 2018 Wolfcamp program was due to precision targeting, high-density stimulations and continued cost reductions. The program shifted toward the development of larger packages of wells during 2018, which also contributed to cost reductions. The high-return Delaware Basin Wolfcamp Shale play will continue to be a primary area of focus in 2019. In the Second Bone Spring play, EOG holds approximately 289,000 net acres and completed 18 net wells in 2018. The Second Bone Spring play is another integral part of EOG's Permian Basin portfolio. In the Leonard Shale play, EOG has approximately 160,000 net acres and continued development with 17 net wells completed in 2018. EOG also had strong results in the First Bone Spring where it holds approximately 100,000 net acres and completed eight net wells in 2018. Activity in 2019 will continue to be focused in the Delaware Basin

Wolfcamp Shale, Second Bone Spring, First Bone Spring and Leonard plays, where EOG expects to complete approximately 270 net wells.

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Activity in the Rocky Mountain area increased in 2018 with a focus on the Wyoming Powder River and DJ Basins. In the Powder River Basin, EOG operated a two-rig program, completing 41 net wells, and identified future drilling locations, mostly in the Mowry and Niobrara formations. The focus in 2019 will be to add infrastructure and operate a drilling program to further delineate the basin and test additional targets, to better position the company for a more robust development program in 2020 and beyond. In the Wyoming DJ Basin, drilling, completion, and operating costs continued to decline and there is a significant high-return development program scheduled for 2019. Drilling activity increased in the Williston Basin in 2018 after pausing for several years while the company reduced its inventory of drilled uncompleted wells (DUCs). The 20 net wells completed in 2018 targeted the Bakken and Three Forks formations and benefited from the application of precision targeting. Activity in 2019 will be similar, as will the seasonal program of completing wells mostly in the summer while drilling operations are conducted throughout the year. EOG currently holds approximately 1.2 million net acres in the Rocky Mountain area.

In the Mid-Continent area, EOG continued its development of the Woodford Oil Window play with 26 net wells completed during 2018. EOG holds 47,000 net acres in the play and plans to build on its initial success in the Woodford Oil Window with 30 net well completions in 2019. In 2018, EOG completed 22 gross (four net) wells in the Western Anadarko Basin Marmaton Sand.

Total net production in 2018 from the Fort Worth Basin Barnett Shale and Marcellus Shale averaged 2 MBbld of crude oil and condensate, 14 MBbld of NGLs and 137 MMcfd of natural gas. Development activity in these areas was concentrated in the Marcellus Shale in 2018, where EOG completed 15 net DUCs. Net production in the Marcellus Shale for 2018 averaged 59 MMcfd of natural gas, with a peak net rate of 102 MMcfd. EOG currently holds approximately 172,000 net acres with Marcellus potential. At year-end 2018, EOG held approximately 152,000 net acres in the Fort Worth Basin.

At year-end 2018, EOG held approximately 441,000 net acres in the Upper Gulf Coast region. EOG remained focused on exploration and evaluation efforts last year with minimal activity and expects these efforts will continue in 2019.

In the South Texas area, EOG completed eight net liquids-rich natural gas wells in 2018, including three net DUCs from prior years. EOG has deferred completion of five additional net wells, and expects to complete these liquids-rich natural gas wells in 2019 in the Frio and Vicksburg trends, where it holds approximately 391,000 net acres. In addition, exploration and evaluation efforts will continue in this region in 2019.

At December 31, 2018, EOG held approximately 2.4 million net undeveloped acres in the United States.

During 2018, EOG continued to operate its gathering and processing facilities in the Eagle Ford in South Texas, the Williston Basin Bakken and Three Forks plays in North Dakota, the Fort Worth Basin Barnett Shale and the Permian Basin in West Texas and New Mexico. At December 31, 2018, EOG-owned natural gas processing capacity in the Eagle Ford and the Fort Worth Basin Barnett Shale totaled 325 MMcfd and 180 MMcfd, respectively.

Operations Outside the United States

EOG has operations offshore Trinidad, in the China Sichuan Basin and in Canada and is evaluating additional exploration, development and exploitation opportunities in these and other select international areas. EOG sold its operations in the United Kingdom (U.K.) East Irish Sea in the fourth quarter of 2018.

Trinidad. EOG, through several of its subsidiaries, including EOG Resources Trinidad Limited,

- holds an 80% working interest in the exploration and production license covering the South East Coast Consortium (SECC) Block offshore Trinidad, except in the Deep Ibis area in which EOG's working interest decreased as a result of a third-party farm-out agreement;

- holds an 80% working interest in the exploration and production license covering the Pelican Field and its related facilities;
- holds a 50% working interest in the exploration and production licenses covering the Sercan Area offshore Trinidad;
- holds a 100% working interest in a production sharing contract with the Government of Trinidad and Tobago for each of the Modified U(a) Block, Modified U(b) Block and Block 4(a);
- holds a 50% working interest in the exploration and production license covering the Banyan Field;
- holds a 50% working interest in the exploration and production license covering the Ska, Mento, Reggae Area deep Teak, deep Saaman and deep Poui offshore Trinidad (collectively SMR Area);
- owns a 12% equity interest in an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Caribbean Nitrogen Company Limited; and

- owns a 10% equity interest in an anhydrous ammonia plant in Point Lisas, Trinidad, that is owned and operated by Nitrogen (2000) Unlimited.

Several fields in the SECC Block, Modified U(a) Block, Modified U(b) Block, Block 4(a), the Banyan Field and the Sercan Area have been developed and are producing natural gas and crude oil and condensate. Natural gas from EOG's Trinidad operations currently is sold under various contracts with the National Gas Company of Trinidad and Tobago Limited and its subsidiary (NGC). Crude oil and condensate from EOG's Trinidad operations currently is sold to the Petroleum Company of Trinidad and Tobago Limited and its successor, Heritage Petroleum Company Limited. In 2018, EOG's net production from Trinidad averaged approximately 266 MMcfd of natural gas and approximately 0.8 MBbld of crude oil and condensate.

In 2018, EOG conducted an ocean bottom nodal seismic survey in the SECC Block and the Pelican Field and continues to process and review the initial data.
In 2019, EOG expects to drill five wells of which two of these wells are expected to be completed during the second quarter of 2019 and one well is expected to be completed in the fourth quarter of 2019. All of the natural gas produced from EOG's Trinidad operations in 2019 is expected to be supplied to NGC under various contracts with NGC. All crude oil and condensate produced from EOG's Trinidad operations in 2019 is expected to be supplied to Heritage Petroleum Company Limited under various contracts with Heritage Petroleum Company Limited.

At December 31, 2018, EOG held approximately 115,000 net undeveloped acres in Trinidad.

United Kingdom. EOG completed the sale of all of its interest in EOG Resources United Kingdom Limited during the fourth quarter of 2018. EOG no longer has any presence in the U.K.

In 2018, production averaged approximately 4.2 MBbld of crude oil, net, in the U.K.

China. In July 2008, EOG acquired rights from ConocoPhillips in a Petroleum Contract covering the Chuan Zhong Block exploration area in the Sichuan Basin, Sichuan Province, China. In October 2008, EOG obtained the rights to shallower zones on the acquired acreage. EOG entered 2018 with two DUCs and completed both wells. In addition, EOG drilled five natural gas wells and completed one of those wells in 2018 as part of the continuing development of the Bajiaochang Field, which natural gas is sold under a long-term contract to PetroChina. EOG plans to drill two additional wells in 2019 and complete the remaining 2018 wells in progress as pipeline capacity allows.

In 2018, production averaged approximately 23 MMcfd of natural gas, net, in China.

Canada. EOG maintains approximately 134,000 net acres with 23 net producing wells in the Horn River area in Northeast British Columbia.

In 2018, net production in Canada averaged approximately 8 MMcfd of natural gas.

EOG continues to evaluate other select crude oil and natural gas opportunities outside the United States, primarily by pursuing exploitation opportunities in countries where indigenous crude oil and natural gas reserves have been identified.

Marketing

In 2018, EOG's wellhead crude oil and condensate production was transported either by pipeline or truck to downstream markets or sold into local markets. In each case, the price received was based on market prices at that specific sales point or based on the price index applicable for that location. Major U.S. sales areas included the Midwest; the Permian Basin; Cushing, Oklahoma; Houston and Corpus Christi, Texas; and Louisiana; and other points along the U.S. Gulf Coast. In 2019, the pricing mechanism for such production is expected to remain the same. At December 31, 2018, EOG is committed to deliver fixed quantities of crude oil of 69.9 MMBbls in 2019, 13.7 MMBbls in 2020 and 1.4 MMBbls in 2021, all of which is expected to be delivered from future production of available reserves.

In 2018, EOG processed certain of its natural gas production, either at EOG-owned facilities or at third-party facilities, extracting NGLs. NGLs were sold at prevailing market prices. In 2019, the pricing mechanism for such production is expected to remain the same.

In 2018, EOG's United States wellhead natural gas production was sold into local markets or transported by pipeline to Katy, Texas; East Texas; the Cheyenne Hub; Southern California; or Chicago, Illinois. Pricing was based on the spot market price at the ultimate sales point. In 2019, the pricing mechanism for such production is expected to remain the same. At December 31, 2018, EOG is committed to deliver fixed quantities of natural gas of 64 Bcf in 2019, 15 Bcf in 2020, 10 Bcf in 2021, 2 Bcf in 2022 and 11 Bcf thereafter, all of which is expected to be delivered from future production of available reserves.

In 2018, a large majority of the wellhead natural gas volumes from Trinidad were sold under contracts with prices which were either wholly or partially dependent on Caribbean ammonia index prices and/or methanol prices. The remaining volumes were sold under a contract at prices partially dependent on United States Henry Hub market prices and a fixed price contract. The pricing mechanisms for these contracts in Trinidad are expected to remain the same in 2019.

In 2018, all wellhead natural gas volumes from China were sold at regulated prices based on the purchaser's pipeline sales volumes to various local market segments. The pricing mechanism for production in China is expected to remain the same in 2019.

Through November 2018, EOG marketed and sold its U.K. wellhead crude oil production from the Conwy field. The crude oil sales were based on a Dated Brent price or other market prices, as applicable.

In certain instances, EOG purchases and sells third-party crude oil and natural gas in order to balance firm transportation capacity with production in certain areas and to utilize excess capacity at EOG-owned facilities.

During 2018, two purchasers each accounted for more than 10% of EOG's total wellhead crude oil and condensate, NGL and natural gas revenues and gathering, processing and marketing revenues. The two purchasers are in the crude oil refining industry. EOG does not believe that the loss of any single purchaser would have a material adverse effect on its financial condition or results of operations.

Wellhead Volumes and Prices

The following table sets forth certain information regarding EOG's wellhead volumes of, and average prices for, crude oil and condensate, NGLs and natural gas. The table also presents crude oil equivalent volumes which are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 Mcf of natural gas for each of the years ended December 31, 2018, 2017 and 2016. See ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations, for wellhead volumes on a per-day basis.

Year Ended December 31	2018	2017	2016
Crude Oil and Condensate Volumes (MMBbl) [(1)]			
United States:			
Eagle Ford	62.4	57.4	60.7
Delaware Basin	46.3	31.6	17.0
Other	35.4	33.2	24.2
United States	144.1	122.2	101.9
Trinidad	0.3	0.3	0.3
Other International [(2)]	1.6	0.2	1.2
Total	146.0	122.7	103.4
Natural Gas Liquids Volumes (MMBbl) [(1)]			
United States:			
Eagle Ford	11.4	9.4	10.0
Delaware Basin	15.8	8.8	5.8
Other	15.3	14.1	14.1
United States	42.5	32.3	29.9
Other International [(2)]	—	—	—
Total	42.5	32.3	29.9
Natural Gas Volumes (Bcf) [(1)]			
United States:			
Eagle Ford	58	55	59
Delaware Basin	110	81	50
Other	169	143	187
United States	337	279	296
Trinidad	97	114	125
Other International [(2)]	11	9	9
Total	445	402	430
Crude Oil Equivalent Volumes (MMBoe) [(3)]			
United States:			
Eagle Ford	83.5	76.0	80.6
Delaware Basin	80.3	53.9	31.2
Other	78.8	71.2	69.3
United States	242.6	201.1	181.1
Trinidad	16.5	19.4	21.1
Other International [(2)]	3.4	1.8	2.8
Total	262.5	222.3	205.0

Year Ended December 31	2018	2017	2016
Average Crude Oil and Condensate Prices ($/Bbl) (4)			
United States	$65.16	$50.91	$41.84
Trinidad	57.26	42.30	33.76
Other International (2)	71.45	57.20	36.72
Composite	65.21	50.91	41.76
Average Natural Gas Liquids Prices ($/Bbl) (4)			
United States	$26.60	$22.61	$14.63
Other International (2)	—	—	—
Composite	26.60	22.61	14.63
Average Natural Gas Prices ($/Mcf) (4)			
United States	$2.88	$2.20	$1.60
Trinidad	2.94	2.38	1.88
Other International (2)	4.08	3.89	3.64
Composite	2.92 (5)	2.29	1.73

(1) Million barrels or billion cubic feet, as applicable.

(2) Other International includes EOG's United Kingdom, China, Canada and Argentina operations. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

(3) Million barrels of oil equivalent; includes crude oil and condensate, NGLs and natural gas.

(4) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments (see Note 12 to Consolidated Financial Statements).

(5) Includes a positive revenue adjustment of $0.44 per Mcf related to the adoption of ASU 2014-09, "Revenue From Contracts with Customers" (ASU 2014-09) (see Note 1 to the Consolidated Financial Statements). In connection with the adoption of ASU 2014-09, EOG presents natural gas processing fees related to certain processing and marketing agreements as Gathering and Processing Costs, instead of as a deduction to Natural Gas revenues.

Competition

EOG competes with major integrated oil and gas companies, government-affiliated oil and gas companies and other independent oil and gas companies for the acquisition of licenses and leases, properties and reserves and access to the facilities, equipment, materials, services, and employees and other contract personnel (including geologists, geophysicists, engineers and other specialists) required to explore for, develop, produce, market and transport crude oil and natural gas. In addition, certain of EOG's competitors have financial and other resources substantially greater than those EOG possesses and have established strategic long-term positions or strong governmental relationships in countries or areas in which EOG may seek new or expanded entry. As a consequence, EOG may be at a competitive disadvantage in certain respects, such as in bidding for drilling rights or in accessing necessary services, facilities, equipment, materials and personnel. In addition, EOG's larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil and natural gas, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. EOG also faces competition, to a lesser extent, from competing energy sources, such as alternative energy sources.

Regulation

United States Regulation of Crude Oil and Natural Gas Production. Crude oil and natural gas production operations are subject to various types of regulation, including regulation by federal and state agencies.

United States legislation affecting the oil and gas industry is under constant review for amendment or expansion. In addition, numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations applicable to the oil and gas industry. Such rules and regulations, among other things, require permits for the drilling of wells, regulate the spacing of wells, prevent the waste of natural gas through restrictions on flaring, require surety bonds for various exploration and production operations and regulate the calculation and disbursement of royalty payments (for federal and state leases), production taxes and ad valorem taxes.

A portion of EOG's oil and gas leases in New Mexico, North Dakota, Utah, Wyoming and the Gulf of Mexico, as well as in other areas, are granted by the federal government and administered by the Bureau of Land Management (BLM) and/or the Bureau of Indian Affairs (BIA) or, in the case of offshore leases (which, for EOG, are de minimis), by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE), all federal agencies. Operations conducted by EOG on federal oil and gas leases must comply with numerous additional statutory and regulatory restrictions and, in the case of leases relating to tribal lands, certain tribal environmental and permitting requirements and employment rights regulations. In addition, the U.S. Department of the Interior (via various of its agencies, including the BLM, the BIA and the Office of Natural Resources Revenue) has certain authority over our calculation and payment of royalties, bonuses, fines, penalties, assessments and other revenues related to our federal and tribal oil and gas leases.

BLM, BIA and BOEM leases contain relatively standardized terms requiring compliance with detailed regulations and, in the case of offshore leases, orders pursuant to the Outer Continental Shelf Lands Act (which are subject to change by the BOEM or BSEE). Under certain circumstances, the BLM, BIA, BOEM or BSEE (as applicable) may require operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect EOG's interests.

The transportation and sale for resale of natural gas in interstate commerce are regulated pursuant to the Natural Gas Act of 1938, as amended (NGA), and the Natural Gas Policy Act of 1978. These statutes are administered by the Federal Energy Regulatory Commission (FERC). Effective January 1993, the Natural Gas Wellhead Decontrol Act of 1989 deregulated natural gas prices for all "first sales" of natural gas, which includes all sales by EOG of its own production. All other sales of natural gas by EOG, such as those of natural gas purchased from third parties, remain jurisdictional sales subject to a blanket sales certificate under the NGA, which has flexible terms and conditions. Consequently, all of EOG's sales of natural gas currently may be made at market prices, subject to applicable contract provisions. EOG's jurisdictional sales, however, may be subject in the future to greater federal oversight, including the possibility that the FERC might prospectively impose more restrictive conditions on such sales. Conversely, sales of crude oil and condensate and NGLs by EOG are made at unregulated market prices.

EOG owns certain gathering and/or processing facilities in the Permian Basin in West Texas and New Mexico, the Barnett Shale in North Texas, the Bakken and Three Forks plays in North Dakota, and the Eagle Ford in South Texas. State regulation of gathering and processing facilities generally includes various safety, environmental and, in some circumstances, nondiscrimination requirements with respect to the provision of gathering and processing services, but does not generally entail rate regulation. EOG's gathering and processing operations could be materially and adversely affected should they be subject in the future to the application of state or federal regulation of rates and services.

EOG's gathering and processing operations also may be, or become, subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of such facilities. Additional rules and legislation pertaining to these matters are considered and/or adopted from time to time. Although EOG cannot predict what effect, if any, such legislation might have on its operations and financial condition, EOG could be required to incur additional capital expenditures and increased compliance and operating costs depending on the nature and extent of such future legislative and regulatory changes.

EOG also owns crude oil rail loading facilities in North Dakota and crude oil truck unloading facilities in certain of its U.S. plays. Regulation of such facilities is conducted at the state and federal levels and generally includes various safety, environmental, permitting and packaging/labeling requirements. Additional regulation pertaining to these matters is considered and/or adopted from time to time. Although EOG cannot predict what effect, if any, any such new regulations might have on its crude-by-rail assets and the transportation of its crude oil production by truck, EOG could be required to incur additional capital expenditures and increased compliance and operating costs depending on the nature and extent of such future regulatory changes. EOG did not transport any crude oil by rail during 2018.

Proposals and proceedings that might affect the oil and gas industry are considered from time to time by Congress, the state legislatures, the FERC and federal, state and local regulatory commissions, agencies, councils and courts. EOG cannot predict when or whether any such proposals or proceedings may become effective. It should also be noted that the oil and gas industry historically has been very heavily regulated; therefore, there is no assurance that the approach currently being followed by such legislative bodies and regulatory commissions, agencies, councils and courts will remain unchanged.

Environmental Regulation - United States. EOG is subject to various federal, state and local laws and regulations covering the discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations affect EOG's operations and costs as a result of their effect on crude oil and natural gas exploration, development and production operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining future operations or imposing additional compliance requirements.

In addition, EOG has acquired certain oil and gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons or other wastes were not under EOG's control. Under environmental laws and regulations, EOG could be required to remove or remediate wastes disposed of or released by prior owners or operators. EOG also could incur costs related to the clean-up of third-party sites to which it sent regulated substances for disposal or to which it sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at such third-party sites. In addition, EOG could be responsible under environmental laws and regulations for oil and gas properties in which EOG previously owned or currently owns an interest, but was or is not the operator. Moreover, EOG is subject to the United States (U.S.) Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of greenhouse gas (GHG) emissions and, as discussed further below, is also subject to federal, state and local laws and regulations regarding hydraulic fracturing.

Compliance with environmental laws and regulations increases EOG's overall cost of business, but has not had, to date, a material adverse effect on EOG's operations, financial condition or results of operations. In addition, it is not anticipated, based on current laws and regulations, that EOG will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such laws and regulations. However, given that such laws and regulations are subject to change, EOG is unable to predict the ultimate cost of compliance or the ultimate effect on EOG's operations, financial condition and results of operations.

Climate Change - United States. Local, state, federal and international regulatory bodies have been increasingly focused on GHG emissions and climate change issues in recent years. In addition to the U.S. EPA's rule requiring annual reporting of GHG emissions, the U.S. EPA has adopted regulations for certain large sources regulating GHG emissions as pollutants under the federal Clean Air Act. In May 2016, the U.S. EPA issued regulations that require operators to reduce methane emissions and emissions of volatile organic compounds (VOC) from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations.

At the international level, in December 2015, the U.S. participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. The Paris Agreement went into effect on November 4, 2016. However, the U.S. has announced its intention to withdraw from the Paris Agreement. In response, many state and local officials have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

EOG believes that its strategy to reduce GHG emissions throughout its operations is both in the best interest of the environment and a prudent business practice. EOG has developed a system that is utilized in calculating GHG emissions from its operating facilities. This emissions management system calculates emissions based on recognized regulatory methodologies, where applicable, and on commonly accepted engineering practices. EOG reports GHG emissions for facilities covered under the U.S. EPA's Mandatory Reporting of Greenhouse Gases Rule published in 2009, as amended.

EOG is unable to predict the timing, scope and effect of any currently proposed or future investigations, laws, regulations or treaties regarding climate change and GHG emissions, but the direct and indirect costs of such investigations, laws, regulations and treaties (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations.

Hydraulic Fracturing - United States. Most onshore crude oil and natural gas wells drilled by EOG are completed and stimulated through the use of hydraulic fracturing. Hydraulic fracturing technology, which has been used by the oil and gas industry for more than 60 years and is constantly being enhanced, enables EOG to produce crude oil and natural gas from formations that otherwise would not be recovered. Specifically, hydraulic fracturing is a process in which pressurized fluid is pumped into underground formations to create tiny fractures or spaces that allow crude oil and natural gas to flow from the reservoir into the well so that it can be brought to the surface. Hydraulic fracturing generally takes place thousands of feet underground, a considerable distance below any drinking water aquifers, and there are impermeable layers of rock between the area fractured and the water aquifers. The makeup of the fluid used in the hydraulic fracturing process typically includes water and sand, and less than 1% of highly diluted chemical additives; lists of the chemical additives used in fracturing fluids are available to the public via internet websites and in other publications sponsored by industry trade associations and through state agencies in those states that require the reporting of the components of fracturing fluids. While the majority of the sand remains underground to hold open the fractures, a significant amount of the water and chemical additives flow back and are then either reused or safely disposed of at sites that are approved and permitted by the appropriate regulatory authorities. EOG periodically conducts regulatory assessments of these disposal facilities to monitor compliance with applicable regulations.

The regulation of hydraulic fracturing is primarily conducted at the state and local level through permitting and other compliance requirements. In April 2012, however, the U.S. EPA issued regulations specifically applicable to the oil and gas industry that require operators to significantly reduce VOC emissions from natural gas wells that are hydraulically fractured through the use of "green completions" to capture natural gas that would otherwise escape into the air. The U.S. EPA also issued regulations that establish standards for VOC emissions from several types of equipment, including storage tanks, compressors, dehydrators, and valves and sweetening units at gas processing plants. In addition, in May 2016, the U.S. EPA issued regulations that require operators to reduce methane and VOC emissions from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations.

In November 2016, the BLM issued a final rule that limits venting, flaring and leaking of natural gas from oil and gas wells and equipment on federal and Indian lands, though, in September 2018, the BLM issued a final rule rescinding certain requirements of that rule. There have been various other proposals to regulate hydraulic fracturing at the federal level. Any new federal regulations that may be imposed on hydraulic fracturing could result in additional permitting and disclosure requirements, additional operating and compliance costs and additional operating restrictions.

In addition to these federal regulations, some state and local governments have imposed or have considered imposing various conditions and restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; disclosure of the chemical additives used in hydraulic fracturing operations; restrictions on the type of chemical additives that may be used in hydraulic fracturing operations; and restrictions on drilling or injection activities on certain lands lying within wilderness wetlands, ecologically or seismically sensitive areas, and other protected areas. Such federal, state and local permitting and disclosure requirements and operating restrictions and conditions could lead to operational delays and increased operating and compliance costs and, moreover, could delay or effectively prevent the development of crude oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing.

EOG is unable to predict the timing, scope and effect of any currently proposed or future laws or regulations regarding hydraulic fracturing in the United States, but the direct and indirect costs of such laws and regulations (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations.

Other International Regulation. EOG's exploration and production operations outside the United States are subject to various types of regulations, including environmental regulations, imposed by the respective governments of the countries in which EOG's operations are conducted, and may affect EOG's operations and costs of compliance within those countries. EOG currently has operations in Trinidad, China and Canada (as earlier discussed, EOG sold its United Kingdom operations in the fourth quarter of 2018). EOG is unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties, including those regarding climate change and hydraulic fracturing, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations. EOG will continue to review the risks to its business and operations associated with all environmental matters, including climate change and hydraulic fracturing regulation. In addition, EOG will continue to monitor and assess any new policies, legislation, regulations and treaties in the areas where it operates to determine the impact on its operations and take appropriate actions, where necessary.

Other Regulation. EOG has sand mining and processing operations in Texas and Wisconsin, which support EOG's exploration and development operations. EOG's sand mining operations are subject to regulation by the federal Mine Safety and Health Administration (in respect of safety and health matters) and by state agencies (in respect of air permitting and other environmental matters). The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this report.

Other Matters

Energy Prices. EOG is a crude oil and natural gas producer and is impacted by changes in prices of crude oil and condensate, NGLs and natural gas. Average crude oil and condensate prices received by EOG for production in the United States increased 28% in 2018 and 22% in 2017 and decreased 12% in 2016, each as compared to the immediately preceding year. Average NGL prices received by EOG for production in the United States increased 18% in 2018, 55% in 2017, and 1% in 2016, each as compared to the immediately preceding year. During the last three years, average United States wellhead natural gas prices have fluctuated, at times rather dramatically. These fluctuations resulted in a 31% increase in the average wellhead natural gas price received by EOG for production in the United States in 2018 (inclusive of a positive revenue adjustment of $0.44 per Mcf related to the adoption of ASU 2014-09), a 38% increase in 2017 and a 19% decrease in 2016, each as compared to the immediately preceding year.

Due to the many uncertainties associated with the world political and economic environment (for example, the actions of other crude oil exporting nations, including the Organization of Petroleum Exporting Countries), the global supply of, and demand for, crude oil, NGLs and natural gas and the availability of other energy supplies, the relative competitive relationships of the various energy sources in the view of consumers and other factors, EOG is unable to predict what changes may occur in prices of crude oil and condensate, NGLs and natural gas in the future. For additional discussion regarding changes in crude oil and condensate, NGLs and natural gas prices and the risks that such changes may present to EOG, see ITEM 1A, Risk Factors.

Based on EOG's tax position, EOG's price sensitivity (exclusive of basis swaps) in 2019 for each $1.00 per barrel increase or decrease in wellhead crude oil and condensate price, combined with the estimated change in NGL price, is approximately $133 million for net income and $173 million for pretax cash flows from operating activities. Based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2019 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf increase or decrease in wellhead natural gas price is approximately $29 million for net income and $37 million for pretax cash flows from operating activities. For a summary of EOG's financial commodity derivative contracts through February 19, 2019, see ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Derivative Transactions. For a summary of EOG's financial commodity derivative contracts for the twelve months ended December 31, 2018, see Note 12 to Consolidated Financial Statements.

Risk Management. EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in prices of crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, option, swaption, collar and basis swap contracts, as a means to manage this price risk. See Note 12 to Consolidated Financial Statements. For a summary of EOG's financial commodity derivative contracts through February 19, 2019, see ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Derivative Transactions.

All of EOG's crude oil and natural gas activities are subject to the risks normally incident to the exploration for, and development, production and transportation of, crude oil and natural gas, including rig and well explosions, cratering, fires, loss of well control and leaks and spills, each of which could result in damage to life, property and/or the environment. EOG's operations are also subject to certain perils, including hurricanes, flooding and other adverse weather events. Moreover, EOG's activities are subject to governmental regulations as well as interruption or termination by governmental authorities based on environmental and other considerations. Losses and liabilities arising from such events could reduce revenues and increase costs to EOG to the extent not covered by insurance.

Insurance is maintained by EOG against some, but not all, of these risks in accordance with what EOG believes are customary industry practices and in amounts and at costs that EOG believes to be prudent and commercially practicable. Specifically, EOG maintains commercial general liability and excess liability coverage provided by third-party insurers for bodily injury or death claims resulting from an incident involving EOG's operations (subject to policy terms and conditions). Moreover, in the event an incident involving EOG's operations results in negative environmental effects, EOG maintains operators extra expense coverage provided by third-party insurers for obligations, expenses or claims that EOG may incur from such an incident, including obligations, expenses or claims in respect of seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the event of a well control incident resulting in negative environmental effects, such operators extra expense coverage would be EOG's primary coverage, with the commercial general liability and excess liability coverage referenced above also providing certain coverage to EOG. All of EOG's drilling activities are conducted on a contractual basis with independent drilling contractors and other third-party service contractors. The indemnification and other risk allocation provisions included in such contracts are negotiated on a contract-by-contract basis and are each based on the particular circumstances of the services being provided and the anticipated operations.

In addition to the above-described risks, EOG's operations outside the United States are subject to certain risks, including the risk of increases in taxes and governmental royalties, changes in laws and policies governing the operations of foreign-based companies, expropriation of assets, unilateral or forced renegotiation or modification of existing contracts with governmental entities, currency restrictions and exchange rate fluctuations. Please refer to ITEM 1A, Risk Factors, for further discussion of the risks to which EOG is subject with respect to its operations outside the United States.

Executive Officers of the Registrant

The current executive officers of EOG and their names and ages (as of February 26, 2019) are as follows:

Name	Age	Position
William R. Thomas	66	Chairman of the Board and Chief Executive Officer
Lloyd W. Helms, Jr.	61	Chief Operating Officer
Kenneth W. Boedeker	56	Executive Vice President, Exploration and Production
Ezra Y. Yacob	42	Executive Vice President, Exploration and Production
Timothy K. Driggers	57	Executive Vice President and Chief Financial Officer
Michael P. Donaldson	56	Executive Vice President, General Counsel and Corporate Secretary

William R. Thomas was elected Chairman of the Board and Chief Executive Officer effective January 2014. He was elected Senior Vice President and General Manager of EOG's Fort Worth, Texas, office in June 2004, Executive Vice President and General Manager of EOG's Fort Worth, Texas, office in February 2007 and Senior Executive Vice President, Exploitation in February 2011. He subsequently served as Senior Executive Vice President, Exploration from July 2011 to September 2011, as President from September 2011 to July 2013 and as President and Chief Executive Officer from July 2013 to December 2013. Mr. Thomas joined a predecessor of EOG in January 1979. Mr. Thomas is EOG's principal executive officer.

Lloyd W. Helms, Jr. was elected Chief Operating Officer in December 2017. Prior to that, he served as Executive Vice President, Exploration and Production from August 2013 to December 2017. He was elected Vice President, Engineering and Acquisitions in September 2006, Vice President and General Manager of EOG's Calgary, Alberta, Canada office in March 2008, and served as Executive Vice President, Operations from February 2012 to August 2013. Mr. Helms joined a predecessor of EOG in February 1981.

Kenneth W. Boedeker was elected Executive Vice President, Exploration and Production in December 2018. He served as Vice President and General Manager of EOG's Denver, Colorado, office from October 2016 to December 2018, and as Vice President, Engineering and Acquisitions from July 2015 to October 2016. Prior to that, Mr. Boedeker held technical and managerial positions of increasing responsibility across multiple offices and functional areas within EOG. Mr. Boedeker joined EOG in July 1994.

Ezra Y. Yacob was elected Executive Vice President, Exploration and Production in December 2017. He served as Vice President and General Manager of EOG's Midland, Texas, office from May 2014 to December 2017. Prior to that, he served as Manager, Division Exploration in EOG's Fort Worth, Texas, and Midland, Texas, offices from March 2012 to May 2014 as well as in various geoscience and leadership positions. Mr. Yacob joined EOG in August 2005.

Timothy K. Driggers was elected Executive Vice President and Chief Financial Officer in April 2016. Previously, Mr. Driggers served as Vice President and Chief Financial Officer from July 2007 to April 2016. He was elected Vice President and Controller of EOG in October 1999, was subsequently named Vice President, Accounting and Land Administration in October 2000 and Vice President and Chief Accounting Officer in August 2003. Mr. Driggers is EOG's principal financial officer. Mr. Driggers joined a predecessor of EOG in August 1995.

Michael P. Donaldson was elected Executive Vice President, General Counsel and Corporate Secretary in April 2016. Previously, Mr. Donaldson served as Vice President, General Counsel and Corporate Secretary from May 2012 to April 2016. He was elected Corporate Secretary in May 2008, and was appointed Deputy General Counsel and Corporate Secretary in July 2010. Mr. Donaldson joined EOG in September 2007.

ITEM 1A. Risk Factors

Our business and operations are subject to many risks. The risks described below may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. If any of the events or circumstances described below actually occurs, our business, financial condition, results of operations or cash flows could be materially and adversely affected and the trading price of our common stock could decline. The following risk factors should be read in conjunction with the other information contained herein, including the consolidated financial statements and the related notes. Unless the context requires otherwise, "we," "us," "our" and "EOG" refer to EOG Resources, Inc. and its subsidiaries.

Crude oil, natural gas and NGL prices are volatile, and a substantial and extended decline in commodity prices can have a material and adverse effect on us.

Prices for crude oil and natural gas (including prices for natural gas liquids (NGLs) and condensate) fluctuate widely. Among the interrelated factors that can or could cause these price fluctuations are:

- domestic and worldwide supplies of crude oil, NGLs and natural gas;
- domestic and international drilling activity;
- the actions of other crude oil producing and exporting nations, including the Organization of Petroleum Exporting Countries;
- consumer and industrial/commercial demand for crude oil, natural gas and NGLs;
- worldwide economic conditions, geopolitical factors and political conditions, including, but not limited to, the imposition of tariffs or trade or other economic sanctions, political instability or armed conflict in oil and gas producing regions;
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- the availability, proximity and capacity of appropriate transportation, gathering, processing, compression, storage and refining facilities;
- the price and availability of, and demand for, competing energy sources, including alternative energy sources;
- the effect of worldwide energy conservation measures, alternative fuel requirements and climate change-related initiatives;
- the nature and extent of governmental regulation, including environmental and other climate change-related regulation, regulation of derivatives transactions and hedging activities, tax laws and regulations and laws and regulations with respect to the import and export of crude oil, natural gas and related commodities;
- the level and effect of trading in commodity futures markets, including trading by commodity price speculators and others; and
- weather conditions and changes in weather patterns.

Beginning in the fourth quarter of 2014 and continuing through 2016, crude oil prices substantially declined. In addition, natural gas and NGL prices began to decline substantially in the second quarter of 2014 and such lower prices continued through 2016. While crude oil, natural gas and NGL prices improved significantly during 2017 and 2018, the above-described factors and the volatility of commodity prices make it difficult to predict future crude oil, natural gas and NGL prices. For example, during the fourth quarter of 2018, there was a substantial decline in the prices for crude oil and NGLs, whereas natural gas prices increased significantly during such period. As a result, there can be no assurance that the prices for crude oil, natural gas and/or NGLs will sustain, or increase from, their current levels and not decline.

Our cash flows and results of operations depend to a great extent on prevailing commodity prices. Accordingly, substantial and extended declines in commodity prices can materially and adversely affect the amount of cash flows we have available for our capital expenditures and other operating expenses, the terms on which we can access the credit and capital markets and our results of operations.

Lower commodity prices can also reduce the amount of crude oil, natural gas and NGLs that we can produce economically. Substantial and extended declines in the prices of these commodities can render uneconomic a portion of our exploration, development and exploitation projects, resulting in our having to make downward adjustments to our estimated proved reserves. In addition, significant prolonged decreases in commodity prices may cause the expected future cash flows from our properties to fall below their respective net book values, which will require us to write down the value of our properties. Such reserve write-downs and asset impairments could materially and adversely affect our results of operations and financial position and, in turn, the trading price of our common stock.

In fact, the substantial declines in crude oil, natural gas, and NGL prices that began in 2014 and continued in 2015 and through 2016 materially and adversely affected the amount of cash flows we had available for our capital expenditures and other operating expenses and our results of operations during fiscal years 2015 and 2016. Such declines also adversely affected the trading price of our common stock.

If commodity prices decline from current levels for an extended period of time, our financial condition, cash flows and results of operations will be adversely affected and we may be limited in our ability to maintain our current level of dividends on our common stock. In addition, we may be required to incur impairment charges and/or make downward adjustments to our proved reserve estimates. As a result, our financial condition and results of operations and the trading price of our common stock may be adversely affected.

Drilling crude oil and natural gas wells is a high-risk activity and subjects us to a variety of risks that we cannot control.

Drilling crude oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive crude oil and natural gas reserves (including "dry holes"). As a result, we may not recover all or any portion of our investment in new wells.

Specifically, we often are uncertain as to the future cost or timing of drilling, completing and operating wells, and our drilling operations and those of our third-party operators may be curtailed, delayed or canceled, the cost of such operations may increase and/or our results of operations and cash flows from such operations may be impacted, as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;

- adverse weather conditions, such as winter storms, flooding, tropical storms and hurricanes, and changes in weather patterns;
- compliance with, or changes in, environmental, health and safety laws and regulations relating to air emissions, hydraulic fracturing, access to and use of water, disposal or other discharge (e.g., into injection wells) of produced water, drilling fluids and other wastes, laws and regulations imposing conditions or restrictions on drilling and completion operations and on the transportation of crude oil and natural gas, and other laws and regulations, such as tax laws and regulations;
- the availability and timely issuance of required federal, state, tribal and other permits and licenses, which may be affected by (among other things) government shutdowns or other suspensions of, or delays in, government services;
- the availability of, costs associated with and terms of contractual arrangements for properties, including mineral licenses and leases, pipelines, crude oil hauling trucks and qualified drivers and facilities and equipment to gather, process, compress, store, transport and market crude oil, natural gas and related commodities; and

- the costs of, or shortages or delays in the availability of, drilling rigs, hydraulic fracturing services, pressure pumping equipment and supplies, tubular materials, water, sand, disposal facilities, qualified personnel and other necessary facilities, equipment, materials, supplies and services.

Our failure to recover our investment in wells, increases in the costs of our drilling operations or those of our third-party operators, and/or curtailments, delays or cancellations of our drilling operations or those of our third-party operators, in each case, due to any of the above factors or other factors, may materially and adversely affect our business, financial condition and results of operations. For related discussion of the risks and potential losses and liabilities inherent in our crude oil and natural gas operations generally, see the immediately following risk factor.

Our crude oil and natural gas operations and supporting activities and operations involve many risks and expose us to potential losses and liabilities, and insurance may not fully protect us against these risks and potential losses and liabilities.

Our crude oil and natural gas operations and supporting activities and operations are subject to all of the risks associated with exploring and drilling for, and producing, gathering, processing, compressing, storing and transporting, crude oil and natural gas, including the risks of:

- well blowouts and cratering;
- loss of well control;
- crude oil spills, natural gas leaks, formation water (i.e., produced water) spills and pipeline ruptures;
- pipe failures and casing collapses;
- uncontrollable flows of crude oil, natural gas, formation water or drilling fluids;
- releases of chemicals, wastes or pollutants;
- adverse weather events, such as winter storms, flooding, tropical storms and hurricanes, and other natural disasters;
- fires and explosions;
- terrorism, vandalism and physical, electronic and cybersecurity breaches;
- formations with abnormal or unexpected pressures;
- leaks or spills in connection with, or associated with, the gathering, processing, compression, storage and transportation of crude oil and natural gas; and
- malfunctions of, or damage to, gathering, processing, compression and transportation facilities and equipment and other facilities and equipment utilized in support of our crude oil and natural gas operations.

If any of these events occur, we could incur losses, liabilities and other additional costs as a result of:

- injury or loss of life;
- damage to, or destruction of, property, facilities, equipment and crude oil and natural gas reservoirs;
- pollution or other environmental damage;
- regulatory investigations and penalties as well as cleanup and remediation responsibilities and costs;
- suspension or interruption of our operations, including due to injunction;
- repairs necessary to resume operations; and
- compliance with laws and regulations enacted as a result of such events.

We maintain insurance against many, but not all, such losses and liabilities in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. However, the occurrence of any of these events and any losses or liabilities incurred as a result of such events, if uninsured or in excess of our insurance coverage, would reduce the funds available to us for our operations and could, in turn, have a material adverse effect on our business, financial condition and results of operations.

Our ability to sell and deliver our crude oil and natural gas production could be materially and adversely affected if adequate gathering, processing, compression, storage and transportation facilities and equipment are unavailable.

The sale of our crude oil and natural gas production depends on a number of factors beyond our control, including the availability, proximity and capacity of, and costs associated with, gathering, processing, compression, storage and transportation facilities and equipment owned by third parties. These facilities may be temporarily unavailable to us due to market conditions, regulatory reasons, mechanical reasons or other factors or conditions, and may not be available to us in the future on terms we consider acceptable, if at all. In particular, in certain newer plays, the capacity of gathering, processing, compression, storage and transportation facilities and equipment may not be sufficient to accommodate potential production from existing and new wells. In addition, lack of financing, construction and permitting delays, permitting costs and regulatory or other constraints could limit or delay the construction, manufacture or other acquisition of new gathering, processing, compression, storage and transportation facilities and equipment by third parties or us, and we may experience delays or increased costs in accessing the pipelines, gathering systems or rail systems necessary to transport our production to points of sale or delivery.

Any significant change in market or other conditions affecting gathering, processing, compression, storage or transportation facilities and equipment or the availability of these facilities, including due to our failure or inability to obtain access to these facilities and equipment on terms acceptable to us or at all, could materially and adversely affect our business and, in turn, our financial condition and results of operations.

If we fail to acquire or find sufficient additional reserves over time, our reserves and production will decline from their current levels.

The rate of production from crude oil and natural gas properties generally declines as reserves are produced. Except to the extent that we conduct successful exploration, exploitation and development activities resulting in additional reserves, acquire additional properties containing reserves or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our reserves will decline as they are produced. Maintaining our production of crude oil and natural gas at, or increasing our production from, current levels, is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves. To the extent we are unsuccessful in acquiring or finding additional reserves, our future cash flows and results of operations and, in turn, the trading price of our common stock could be materially and adversely affected.

We incur certain costs to comply with government regulations, particularly regulations relating to environmental protection and safety, and could incur even greater costs in the future.

Our crude oil and natural gas operations and supporting activities are regulated extensively by federal, state, tribal and local governments and regulatory agencies, both domestically and in the foreign countries in which we do business, and are subject to interruption or termination by governmental and regulatory authorities based on environmental, health, safety or other considerations. Moreover, we have incurred and will continue to incur costs in our efforts to comply with the requirements of environmental, health, safety and other regulations. Further, the regulatory environment could change in ways that we cannot predict and that might substantially increase our costs of compliance and, in turn, materially and adversely affect our business, results of operations and financial condition.

Specifically, as a current or past owner or lessee and operator of crude oil and natural gas properties, we are subject to various federal, state, tribal, local and foreign regulations relating to the discharge of materials into, and the protection of, the environment. These regulations may, among other things, impose liability on us for the cost of pollution cleanup resulting from current or past operations, subject us to liability for pollution damages and require suspension or cessation of operations in affected areas. Changes in, or additions to, these regulations could lead to increased operating and compliance costs and, in turn, materially and adversely affect our business, results of operations and financial condition.

Local, state, federal and international regulatory bodies have been increasingly focused on greenhouse gas (GHG) emissions and climate change issues in recent years. For example, we are subject to the United States (U.S.) Environmental Protection Agency's (U.S. EPA) rule requiring annual reporting of GHG emissions. In addition, in May 2016, the U.S. EPA issued regulations that require operators to reduce methane emissions and emissions of volatile organic compounds from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations.

At the international level, in December 2015, the U.S. participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. The Paris Agreement went into effect on November 4, 2016. However, the U.S. has announced its intention to withdraw from the Paris Agreement. In response, many state and local officials have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

It is possible that the Paris Agreement and subsequent domestic and international regulations will have adverse effects on the market for crude oil, natural gas and other fossil fuel products as well as adverse effects on the business and operations of companies engaged in the exploration for, and production of, crude oil, natural gas and other fossil fuel products. EOG is unable to predict the timing, scope and effect of any currently proposed or future investigations, laws, regulations or treaties regarding climate change and GHG emissions, but the direct and indirect costs of such investigations, laws, regulations and treaties (if enacted) could materially and adversely affect EOG's operations, financial condition and results of operations.

The regulation of hydraulic fracturing is primarily conducted at the state and local level through permitting and other compliance requirements. In November 2016, however, the U.S. Bureau of Land Management (BLM) issued a final rule that limits venting, flaring and leaking of natural gas from oil and gas wells and equipment on federal and Indian lands (in September 2018, the BLM issued a final rule rescinding certain requirements of the rule). In addition, the U.S. EPA has issued regulations relating to hydraulic fracturing and there have been various other proposals to regulate hydraulic fracturing at the federal level. Any new federal regulations that may be imposed on hydraulic fracturing could result in additional permitting and disclosure requirements, additional operating and compliance costs and additional operating restrictions. Moreover, some state and local governments have imposed or have considered imposing various conditions and restrictions on drilling and completion operations. Any such federal or state requirements, restrictions or conditions could lead to operational delays and increased operating and compliance costs and, moreover, could delay or effectively prevent the development of crude oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. Accordingly, our production of crude oil and natural gas could be materially and adversely affected. For additional discussion regarding climate change regulation and hydraulic fracturing regulation, see Climate Change - United States and Hydraulic Fracturing - United States under ITEM 1, Business - Regulation.

We will continue to monitor and assess any proposed or new policies, legislation, regulations and treaties in the areas where we operate to determine the impact on our operations and take appropriate actions, where necessary. We are unable to predict the timing, scope and effect of any currently proposed or future laws, regulations or treaties, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect our business, results of operations and financial condition. For related discussion, see the risk factor below regarding the provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act with respect to regulation of derivatives transactions and entities (such as EOG) that participate in such transactions.

Tax laws and regulations applicable to crude oil and natural gas exploration and production companies may change over time, and such changes could materially and adversely affect our cash flows, results of operations and financial condition.

From time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal income tax laws applicable to crude oil and natural gas exploration and production companies, such as with respect to the intangible drilling and development costs deduction and bonus tax depreciation. While these specific changes were not included in the Tax Cuts and Jobs Act signed into law in December 2017, no accurate prediction can be made as to whether any such legislative changes or similar or other tax law changes will be proposed in the future and, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of certain U.S. federal income tax deductions, as well as any other changes to, or the imposition of new, federal, state, local or non-U.S. taxes (including the imposition of, or increases in, production, severance or similar taxes), could materially and adversely affect our cash flows, results of operations and financial condition.

A portion of our crude oil and natural gas production may be subject to interruptions that could have a material and adverse effect on us.

A portion of our crude oil and natural gas production may be interrupted, or shut in, from time to time for various reasons, including, but not limited to, as a result of accidents, weather conditions, the unavailability of gathering, processing, compression, storage, transportation or refining facilities or equipment or field labor issues, or intentionally as a result of market conditions such as crude oil or natural gas prices that we deem uneconomic. If a substantial amount of our production is interrupted or shut in, our cash flows and, in turn, our financial condition and results of operations could be materially and adversely affected.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. In addition, a third-party operator could also decide to shut-in or curtail production from wells, or plug and abandon marginal wells, on properties owned by that operator during periods of lower crude oil or natural gas prices. These limitations and our dependence on the operator and third-party working interest owners for these projects could cause us to incur unexpected future costs, lower production and materially and adversely affect our financial condition and results of operations.

If we acquire crude oil and natural gas properties, our failure to fully identify existing and potential problems, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.

From time to time, we seek to acquire crude oil and natural gas properties - for example, our October 2016 mergers and related asset purchase transactions with Yates Petroleum Corporation and certain of its affiliated entities. Although we perform reviews of properties to be acquired in a manner that we believe is duly diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems (such as title or environmental issues), nor may they permit us to become sufficiently familiar with the properties in order to assess fully their deficiencies and potential. Even when problems with a property are identified, we often may assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements.

In addition, there are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves (as discussed further below), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

We have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms, if at all.

We make, and will continue to make, substantial capital expenditures for the acquisition, exploration, development, production and transportation of crude oil and natural gas reserves. We intend to finance our capital expenditures primarily through our cash flows from operations, commercial paper borrowings, sales of non-core assets and borrowings under other uncommitted credit facilities and, to a lesser extent and if and as necessary, bank borrowings, borrowings under our revolving credit facility and public and private equity and debt offerings.

Lower crude oil and natural gas prices, however, reduce our cash flows and could also delay or impair our ability to consummate certain planned non-core asset sales and divestitures. Further, if the condition of the credit and capital markets materially declines, we might not be able to obtain financing on terms we consider acceptable, if at all. In addition, weakness and/or volatility in domestic and global financial markets or economic conditions or a depressed commodity price environment may increase the interest rates that lenders and commercial paper investors require us to pay or adversely affect our ability to finance our capital expenditures through equity or debt offerings or other borrowings.

Similarly, a reduction in our cash flows (for example, as a result of lower crude oil and natural gas prices or unanticipated well shut-ins) and the corresponding adverse effect on our financial condition and results of operations may also increase the interest rates that lenders and commercial paper investors require us to pay. A substantial increase in interest rates would decrease our net cash flows available for reinvestment. Any of these factors could have a material and adverse effect on our business, financial condition and results of operations.

Further, our ability to obtain financings, our borrowing costs and the terms of any financings are, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. The interrelated factors that may impact our credit ratings include our debt levels; planned asset purchases or sales; near-term and long-term production growth opportunities; liquidity; asset quality; cost structure; product mix; and commodity pricing levels (including, but not limited to, the estimates and assumptions of credit rating agencies with respect to future commodity prices). We cannot provide any assurance that our current credit ratings will remain in effect for any given period of time or that our credit ratings will be raised in the future, nor can we provide any assurance that any of our credit ratings will not be lowered.

The inability of our customers and other contractual counterparties to satisfy their obligations to us may have a material and adverse effect on us.

We have various customers for the crude oil, natural gas and related commodities that we produce as well as various other contractual counterparties, including several financial institutions and affiliates of financial institutions. Domestic and global economic conditions, including the financial condition of financial institutions generally, may adversely affect the ability of our customers and other contractual counterparties to pay amounts owed to us from time to time and to otherwise satisfy their contractual obligations to us, as well as their ability to access the credit and capital markets for such purposes.

Moreover, our customers and other contractual counterparties may be unable to satisfy their contractual obligations to us for reasons unrelated to these conditions and factors, such as the unavailability of required facilities or equipment due to mechanical failure or market conditions. Furthermore, if a customer is unable to satisfy its contractual obligation to purchase crude oil, natural gas or related commodities from us, we may be unable to sell such production to another customer on terms we consider acceptable, if at all, due to the geographic location of such production; the availability, proximity and capacity of appropriate gathering, processing, compression, storage, transportation and refining facilities; or market or other factors and conditions.

The inability of our customers and other contractual counterparties to pay amounts owed to us and to otherwise satisfy their contractual obligations to us may materially and adversely affect our business, financial condition, results of operations and cash flows.

Competition in the oil and gas exploration and production industry is intense, and many of our competitors have greater resources than we have.

We compete with major integrated oil and gas companies, government-affiliated oil and gas companies and other independent oil and gas companies for the acquisition of licenses and leases, properties and reserves and access to the facilities, equipment, materials, services and employees and other contract personnel (including geologists, geophysicists, engineers and other specialists) necessary to explore for, develop, produce, market and transport crude oil and natural gas. In addition, certain of our competitors have financial and other resources substantially greater than those we possess and have established strategic long-term positions or strong governmental relationships in countries or areas in which we may seek new or expanded entry. As a consequence, we may be at a competitive disadvantage in certain respects, such as in bidding for drilling rights or in accessing necessary services, facilities, equipment, materials and personnel. In addition, our larger competitors may have a competitive advantage when responding to factors that affect demand for crude oil and natural gas, such as changing worldwide prices and levels of production and the cost and availability of alternative fuels. We also face competition, to a lesser extent, from competing energy sources, such as alternative energy sources.

Reserve estimates depend on many interpretations and assumptions that may turn out to be inaccurate. Any significant inaccuracies in these interpretations and assumptions could cause the reported quantities of our reserves to be materially misstated.

Estimating quantities of crude oil, NGL and natural gas reserves and future net cash flows from such reserves is a complex, inexact process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors, made by our management and our independent petroleum consultants. Any significant inaccuracies in these interpretations or assumptions could cause the reported quantities of our reserves and future net cash flows from such reserves to be overstated or understated. Also, the data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, continual reassessment of the viability of production under varying economic conditions and improvements and other changes in geological, geophysical and engineering evaluation methods.

To prepare estimates of our economically recoverable crude oil, NGL and natural gas reserves and future net cash flows from our reserves, we analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, gathering, processing, compression, storage and transportation costs, severance, ad valorem and other applicable taxes, capital expenditures and workover and remedial costs, many of which factors are or may be beyond our control. Our actual reserves and future net cash flows from such reserves most likely will vary from our estimates. Any significant variance, including any significant revisions or "write-downs" to our existing reserve estimates, could materially and adversely affect our business, financial condition and results of operations and, in turn, the trading price of our common stock. For related discussion, see ITEM 2, Properties - Oil and Gas Exploration and Production - Properties and Reserves and Supplemental Information to Consolidated Financial Statements.

Weather and climate may have a significant and adverse impact on us.

Demand for crude oil and natural gas is, to a degree, dependent on weather and climate, which impacts, among other things, the price we receive for the commodities we produce and, in turn, our cash flows and results of operations. For example, relatively warm temperatures during a winter season generally result in relatively lower demand for natural gas (as less natural gas is used to heat residences and businesses) and, as a result, lower prices for natural gas production.

In addition, there has been public discussion that climate change may be associated with more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, which could affect some, or all, of our operations. Our exploration, exploitation and development activities and equipment could be adversely affected by extreme weather events, such as winter storms, flooding and tropical storms and hurricanes in the Gulf of Mexico, which may cause a loss of production from temporary cessation of activity or damaged facilities and equipment. Such extreme weather events could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs, the installation and operation of gathering, processing, compression, storage and transportation facilities and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression, storage and transportation services. Such extreme weather events and changes in weather patterns may materially and adversely affect our business and, in turn, our financial condition and results of operations.

Our hedging activities may prevent us from benefiting fully from increases in crude oil and natural gas prices and may expose us to other risks, including counterparty risk.

We use derivative instruments (primarily financial basis swap, price swap, option, swaption and collar contracts) to hedge the impact of fluctuations in crude oil and natural gas prices on our results of operations and cash flows. To the extent that we engage in hedging activities to protect ourselves against commodity price declines, we may be prevented from fully realizing the benefits of increases in crude oil and natural gas prices above the prices established by our hedging contracts. At February 19, 2019, our forecasted crude oil production (excluding basis swap contracts) for 2019 and our forecasted natural gas production for 2019 were not hedged. As a result, our forecasted production for 2019 is subject to fluctuating market prices. If we do not hedge additional production volumes for 2019 and beyond, we will be impacted by commodity price declines, which may result in lower net cash provided by operating activities. In addition, our hedging activities may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts.

Federal legislation and related regulations regarding derivatives transactions could have a material and adverse impact on our hedging activities.

As discussed in the risk factor immediately above, we use derivative instruments to hedge the impact of fluctuations in crude oil and natural gas prices on our results of operations and cash flows. In 2010, Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which, among other matters, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission (CFTC), the U.S. Securities and Exchange Commission (SEC) and certain federal agencies that regulate the banking and insurance sectors (the Prudential Regulators) adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain categories of swaps and may result in certain market participants needing to curtail their derivatives activities. Although some of the rules necessary to implement the Dodd-Frank Act are yet to be adopted, the CFTC, the SEC and the Prudential Regulators have issued numerous rules, including a rule establishing an "end-user" exception to mandatory clearing (End-User Exception), a rule regarding margin for uncleared swaps (Margin Rule) and a proposed rule imposing position limits (Position Limits Rule).

We qualify as a "non-financial entity" for purposes of the End-User Exception and, as such, we are eligible for, and expect to utilize, such exception. As a result, our hedging activities will not be subject to mandatory clearing or the margin requirements imposed in connection with mandatory clearing. We also qualify as a "non-financial end user" for purposes of the Margin Rule; therefore, our uncleared swaps are not subject to regulatory margin requirements. Finally, we believe our hedging activities would constitute bona fide hedging under the Position Limits Rule and would not be subject to limitation under such rule if it is enacted. However, many of our hedge counterparties and many other market participants may not be eligible for the End-User Exception, may be subject to mandatory clearing or the Margin Rule for swaps with some or all of their other swap counterparties, and/or may be subject to the Position Limits Rule. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations related to derivatives (collectively, Foreign Regulations) which may apply to our transactions with counterparties subject to such Foreign Regulations.

The Dodd-Frank Act, the rules adopted thereunder and the Foreign Regulations could increase the cost of derivative contracts, alter the terms of derivative contracts, reduce the availability of derivatives to protect against the price risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If our use of derivatives is reduced as a result of the Dodd-Frank Act, related regulations or the Foreign 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, our capital expenditure requirements. Any of these consequences could have a material and adverse effect on our business, financial condition and results of operations.

Our business and prospects for future success depend to a significant extent upon the continued service and performance of our management team.

Our business and prospects for future success, including the successful implementation of our strategies and handling of issues integral to our future success, depend to a significant extent upon the continued service and performance of our management team. The loss of any member of our management team, and our inability to attract, motivate and retain substitute management personnel with comparable experience and skills, could materially and adversely affect our business, financial condition and results of operations.

We operate in other countries and, as a result, are subject to certain political, economic and other risks.

Our operations in jurisdictions outside the U.S. are subject to various risks inherent in foreign operations. These risks include, among other risks:

- increases in taxes and governmental royalties;
- changes in laws and policies governing operations of foreign-based companies;
- loss of revenue, loss of or damage to equipment, property and other assets and interruption of operations as a result of expropriation, nationalization, acts of terrorism, war, civil unrest and other political risks;
- unilateral or forced renegotiation, modification or nullification of existing contracts with governmental entities;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations; and
- currency restrictions or exchange rate fluctuations.

Our international operations may also be adversely affected by U.S. laws and policies affecting foreign trade and taxation, including tariffs or trade or other economic sanctions and modifications to, or withdrawal from, international trade treaties. The realization of any of these factors could materially and adversely affect our business, financial condition and results of operations.

Unfavorable currency exchange rate fluctuations could adversely affect our results of operations.

The reporting currency for our financial statements is the U.S. dollar. However, certain of our subsidiaries are located in countries other than the U.S. and have functional currencies other than the U.S. dollar. The assets, liabilities, revenues and expenses of certain of these foreign subsidiaries are denominated in currencies other than the U.S. dollar. To prepare our consolidated financial statements, we must translate those assets, liabilities, revenues and expenses into U.S. dollars at then-applicable exchange rates. Consequently, increases and decreases in the value of the U.S. dollar versus other currencies will affect the amount of these items in our consolidated financial statements, even if the amount has not changed in the original currency. These translations could result in changes to our results of operations from period to period. For the fiscal year ended December 31, 2018, less than 1% of our net operating revenues related to operations of our foreign subsidiaries whose functional currency was not the U.S. dollar.

Our business could be adversely affected by security threats, including cybersecurity threats.

We face various security threats, including cybersecurity threats to gain unauthorized access to our sensitive information or to render our information or systems unusable, and threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing facilities, refineries, rail facilities and pipelines. The potential for such security threats subjects our operations to increased risks that could have a material adverse effect on our business, financial condition and results of operations. For example, unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruptions, or other disruptions to our operations.

Our implementation of various procedures and controls to monitor and mitigate such security threats and to increase security for our information, systems, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of, or damage to, sensitive information or facilities, infrastructure and systems essential to our business and operations, as well as data corruption, reputational damage,communication interruptions or other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position and results of operations.

Terrorist activities and military and other actions could materially and adversely affect us.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. The U.S. government has at times issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. Any such actions and the threat of such actions could materially and adversely affect us in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in crude oil and natural gas prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business, financial condition and results of operations.

ITEM 1B. Unresolved Staff Comments

Not applicable.

ITEM 2. Properties

Oil and Gas Exploration and Production - Properties and Reserves

Reserve Information. For estimates and discussions of EOG's net proved reserves of crude oil and condensate, natural gas liquids (NGLs) and natural gas, the qualifications of the preparers of EOG's reserve estimates, EOG's independent petroleum consultants and EOG's processes and controls with respect to its reserve estimates, see "Supplemental Information to Consolidated Financial Statements."

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth in "Supplemental Information to Consolidated Financial Statements" represent only estimates. Reserve engineering is a complex subjective process of estimating underground accumulations of crude oil and condensate, NGLs and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the amount and quality of available data and of engineering and geological interpretation and judgment. As a result, estimates by different engineers normally vary. In addition, results of drilling, testing and production or fluctuations in commodity prices subsequent to the date of an estimate may justify revision of such estimate (upward or downward). Accordingly, reserve estimates are often different from the quantities ultimately recovered. Further, the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based. For related discussion, see ITEM 1A, Risk Factors, and "Supplemental Information to Consolidated Financial Statements."

In general, the rate of production from crude oil and natural gas properties declines as reserves are produced. Except to the extent EOG acquires additional properties containing proved reserves, conducts successful exploration, exploitation and development activities or, through engineering studies, identifies additional behind-pipe zones or secondary recovery reserves, the proved reserves of EOG will decline as reserves are produced. The volumes to be generated from future activities of EOG are therefore highly dependent upon the level of success in finding or acquiring additional reserves. For related discussion, see ITEM 1A, Risk Factors. EOG's estimates of reserves filed with other federal agencies are consistent with the information set forth in "Supplemental Information to Consolidated Financial Statements."

Acreage. The following table summarizes EOG's gross and net developed and undeveloped acreage at December 31, 2018. Excluded is acreage in which EOG's interest is limited to owned royalty, overriding royalty and other similar interests.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	2,618,624	1,884,489	3,280,867	2,409,792	5,899,491	4,294,281
Trinidad	79,277	67,474	201,435	115,274	280,712	182,748
China	130,548	130,548	—	—	130,548	130,548
Canada	40,000	35,771	105,560	98,436	145,560	134,207
Total	2,868,449	2,118,282	3,587,862	2,623,502	6,456,311	4,741,784

Most of our undeveloped oil and gas leases, particularly in the United States, are subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. Approximately 0.3 million net acres will expire in 2019, 0.5 million net acres will expire in 2020 and 0.3 million net acres will expire in 2021 if production is not established or we take no other action to extend the terms of the leases or obtain concessions. In the ordinary course of business, based on our evaluations of certain geologic trends and prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future. As of December 31, 2018, there were no proved undeveloped reserves associated with such undeveloped acreage.

Productive Well Summary. The following table represents EOG's gross and net productive wells, including 2,107 wells in which we hold a royalty interest.

	Crude Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	9,023	6,422	6,360	3,658	15,383	10,080
Trinidad	2	2	33	27	35	29
China	—	—	36	36	36	36
Canada	—	—	24	23	24	23
Total (1)	9,025	6,424	6,453	3,744	15,478	10,168

(1) EOG operated 11,366 gross and 9,744 net producing crude oil and natural gas wells at December 31, 2018. Gross crude oil and natural gas wells include 316 wells with multiple completions.

Drilling and Acquisition Activities. During the years ended December 31, 2018, 2017 and 2016, EOG expended $6.4 billion, $4.4 billion and $6.4 billion, respectively, for exploratory and development drilling, facilities and acquisition of leases and producing properties, including asset retirement obligations of $70 million, $56 million and $(20) million, respectively. Included in the 2016 expenditures was $3.9 billion of acquisitions of producing properties and leases in connection with the 2016 merger and related asset purchase transactions with Yates Petroleum Corporation and other affiliated entities. The following tables set forth the results of the gross crude oil and natural gas wells completed for the years ended December 31, 2018, 2017 and 2016:

	Gross Development Wells Completed				Gross Exploratory Wells Completed			
	Crude Oil	Natural Gas	Dry Hole	Total	Crude Oil	Natural Gas	Dry Hole	Total
2018								
United States	834	39	22	895	—	—	1	1
Trinidad	—	—	—	—	—	—	—	—
China	—	1	—	1	—	2	—	2
Total	834	40	22	896	—	2	1	3
2017								
United States	568	22	13	603	—	—	1	1
Trinidad	—	8	—	8	—	1	—	1
China	—	3	—	3	—	—	1	1
Total	568	33	13	614	—	1	2	3
2016								
United States	524	39	6	569	1	—	—	1
Trinidad	—	1	—	1	—	—	—	—
Total	524	40	6	570	1	—	—	1

The following tables set forth the results of the net crude oil and natural gas wells completed for the years ended December 31, 2018, 2017 and 2016:

	Net Development Wells Completed				Net Exploratory Wells Completed			
	Crude Oil	Natural Gas	Dry Hole	Total	Crude Oil	Natural Gas	Dry Hole	Total
2018								
United States	704	37	18	759	—	—	1	1
Trinidad	—	—	—	—	—	—	—	—
China	—	1	—	1	—	2	—	2
Total	704	38	18	760	—	2	1	3
2017								
United States	490	21	13	524	—	—	1	1
Trinidad	—	6	—	6	—	1	—	1
China	—	3	—	3	—	—	1	1
Total	490	30	13	533	—	1	2	3
2016								
United States	420	17	6	443	1	—	—	1
Trinidad	—	1	—	1	—	—	—	—
Total	420	18	6	444	1	—	—	1

EOG participated in the drilling of wells that were in the process of being drilled or completed at the end of the period as set out in the table below for the years ended December 31, 2018, 2017 and 2016:

	Wells in Progress at End of Period					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
United States	297	238	247	208	237	194
Trinidad	—	—	—	—	1	1
China	4	4	1	1	—	—
Total	301	242	248	209	238	195

Included in the previous table of wells in progress at the end of the period were wells which had been drilled, but were not completed (DUCs). In order to effectively manage its capital expenditures and to provide flexibility in managing its drilling rig and well completion schedules, EOG, from time to time, will have an inventory of DUCs. At December 31, 2018, there were approximately 78 MMBoe of net proved undeveloped reserves (PUDs) associated with EOG's inventory of DUCs. Under EOG's current drilling plan, all such DUCs are expected to be completed within five years from the original booking date of such reserves. The following table sets forth EOG's DUCs, for which PUDs had been booked, as of the end of each period.

	Drilled Uncompleted Wells at End of Period					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
United States	168	137	147	121	173	137
China	3	3	1	1	—	—
Total	171	140	148	122	173	137

EOG acquired wells as set forth in the following tables as of the end of each period (excluding the acquisition of additional interests in 114, 29 and 63 net wells in which EOG previously owned an interest for the years ended December 31, 2018, 2017 and 2016, respectively):

	Gross Acquired Wells			Net Acquired Wells		
	Crude Oil	Natural Gas	Total	Crude Oil	Natural Gas	Total
2018						
United States	15	13	28	10	6	16
Total	15	13	28	10	6	16
2017						
United States	12	3	15	6	2	8
Total	12	3	15	6	2	8
2016						
United States	4,112	4,144	8,256	1,228	2,297	3,525
Total	4,112	4,144	8,256	1,228	2,297	3,525

All of EOG's drilling and completion activities are conducted on a contractual basis with independent drilling contractors and other third-party service contractors. EOG's other property, plant and equipment primarily includes gathering, transportation and processing infrastructure assets, buildings, crude-by-rail assets, and sand mine and sand processing assets which support EOG's exploration and production activities. EOG does not own drilling rigs, hydraulic fracturing equipment or rail cars.

ITEM 3. Legal Proceedings

See the information set forth under the "Contingencies" caption in Note 8 of the Notes to Consolidated Financial Statements, which is incorporated by reference herein.

ITEM 4. Mine Safety Disclosures

The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this report.

PART II

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

EOG's common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol "EOG."

As of February 14, 2019, there were approximately 2,100 record holders and approximately 454,000 beneficial owners of EOG's common stock.

The following table sets forth, for the periods indicated, EOG's share repurchase activity:

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs (2)
October 1, 2018 - October 31, 2018	29,765	$ 128.17	—	6,386,200
November 1, 2018 - November 30, 2018	2,062	104.60	—	6,386,200
December 1, 2018 - December 31, 2018	7,415	98.11	—	6,386,200
Total	39,242	$ 121.26		

(1) The 39,242 total shares for the quarter ended December 31, 2018, and the 538,892 total shares for the full year 2018, consist solely of shares that were withheld by or returned to EOG (i) in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or stock-settled stock appreciation rights or the vesting of restricted stock, restricted stock unit or performance unit grants or (ii) in payment of the exercise price of employee stock options. These shares do not count against the 10 million aggregate share repurchase authorization of EOG's Board discussed below.

(2) In September 2001, the Board authorized the repurchase of up to 10,000,000 shares of EOG's common stock. During 2018, EOG did not repurchase any shares under the Board-authorized repurchase program.

Comparative Stock Performance

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the United States Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that EOG specifically requests that such information be treated as "soliciting material" or specifically incorporates such information by reference into such a filing.

The performance graph shown below compares the cumulative five-year total return to stockholders on EOG's common stock as compared to the cumulative five-year 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 O&G E&P). The comparison was prepared based upon the following assumptions:

1. $100 was invested on December 31, 2013 in each of the following: common stock of EOG, the S&P 500 and the S&P O&G E&P.
2. Dividends are reinvested.

Comparison of Five-Year Cumulative Total Returns
EOG, S&P 500 and S&P O&G E&P
(Performance Results Through December 31, 2018)

	2013	2014	2015	2016	2017	2018
EOG	$100.00	$110.30	$85.45	$123.08	$132.28	$107.59
S&P 500	$100.00	$113.69	$115.27	$129.06	$157.23	$150.34
S&P O&G E&P	$100.00	$89.41	$58.88	$78.21	$73.28	$58.99

ITEM 6. Selected Financial Data
(In Thousands, Except Per Share Data)

The following selected consolidated financial information should be read in conjunction with ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and ITEM 8, Financial Statements and Supplementary Data.

Year Ended December 31	2018	2017	2016	2015	2014
Statement of Income Data:					
Operating Revenues and Other (1)	$17,275,399	$11,208,320	$7,650,632	$8,757,428	$18,035,340
Operating Income (Loss)	$4,469,346	$926,402	$(1,225,281)	$(6,686,079)	$5,241,823
Net Income (Loss)	$3,419,040	$2,582,579	$(1,096,686)	$(4,524,515)	$2,915,487
Net Income (Loss) Per Share					
Basic	$5.93	$4.49	$(1.98)	$(8.29)	$5.36
Diluted	$5.89	$4.46	$(1.98)	$(8.29)	$5.32
Dividends Per Common Share	$0.810	$0.670	$0.670	$0.670	$0.585
Average Number of Common Shares					
Basic	576,578	574,620	553,384	545,697	543,443
Diluted	580,441	578,693	553,384	545,697	548,539

At December 31	2018	2017	2016	2015	2014
Balance Sheet Data:					
Total Property, Plant and Equipment, Net	$28,075,519	$25,665,037	$25,707,078	$24,210,721	$29,172,644
Total Assets (2) (3)	33,934,474	29,833,078	29,299,201	26,834,908	34,758,599
Total Debt (3)	6,083,262	6,387,071	6,986,358	6,655,490	5,905,846
Total Stockholders' Equity	19,364,188	16,283,273	13,981,581	12,943,035	17,712,582

(1) Effective January 1, 2018, EOG adopted the provisions of Accounting Standards Update (ASU) 2014-09, "Revenue From Contracts With Customers" (ASU 2014-09). In connection with the adoption of ASU 2014-09, EOG presents natural gas processing fees relating to certain processing and marketing agreements within its United States segment as Gathering and Processing Costs instead of as a deduction to Natural Gas Revenues. There was no impact to operating income, net income or cash flows resulting from changes to the presentation of natural gas processing fees. EOG elected to adopt ASU 2014-09 using the modified retrospective approach with no reclassification of amounts for the years ended December 31, 2017, 2016, 2015 and 2014 (see Note 1 to Consolidated Financial Statements).

(2) Effective January 1, 2017, EOG adopted the provisions of ASU 2015-17, "Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes" (ASU 2015-17), which simplifies the presentation of deferred taxes in a classified balance sheet by eliminating the requirement to separate deferred income tax liabilities and assets into current and noncurrent amounts. Instead, ASU 2015-17 requires that all deferred tax liabilities and assets be shown as noncurrent in a classified balance sheet. In connection with the adoption of ASU 2015-17, EOG restated its Consolidated Balance Sheets at December 31, 2016 and 2015 by $160 million and $136 million, respectively, from deferred tax liabilities to deferred tax assets.

(3) Effective January 1, 2016, EOG adopted the provisions of ASU 2015-03, "Interest - Computation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs" (ASU 2015-03). ASU 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct reduction from the related debt liability rather than as an asset. In connection with the adoption of ASU 2015-03, EOG restated its Consolidated Balance Sheets at December 31, 2015 and 2014 by $4.8 million and $4.1 million, respectively, of unamortized debt issuance costs from Other Assets to Long-Term Debt.

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

Overview

EOG Resources, Inc., together with its subsidiaries (collectively, EOG), is one of the largest independent (non-integrated) crude oil and natural gas companies in the United States with proved reserves in the United States, Trinidad and China. EOG operates under a consistent business and operational strategy that focuses predominantly on maximizing the rate of return on investment of capital by controlling operating and capital costs and maximizing reserve recoveries. Each prospective drilling location is evaluated by its estimated rate of return. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis, allowing EOG to deliver long-term production growth while maintaining a strong balance sheet. EOG implements its strategy primarily by emphasizing the drilling of internally generated prospects in order to find and develop low-cost reserves. Maintaining the lowest possible operating cost structure that is consistent with efficient, safe and environmentally responsible operations is also an important goal in the implementation of EOG's strategy.

EOG realized net income of $3,419 million during 2018 as compared to net income of $2,583 million for 2017. At December 31, 2018, EOG's total estimated net proved reserves were 2,928 million barrels of oil equivalent (MMBoe), an increase of 401 MMBoe from December 31, 2017. During 2018, net proved crude oil and condensate and natural gas liquids (NGLs) reserves increased by 330 million barrels (MMBbl), and net proved natural gas reserves increased by 424 billion cubic feet or 71 MMBoe, in each case from December 31, 2017.

Operations

Several important developments have occurred since January 1, 2018.

United States. EOG's efforts to identify plays with large reserve potential have proven to be successful. EOG continues to drill numerous wells in large acreage plays, which in the aggregate have contributed substantially to, and are expected to continue to contribute substantially to, EOG's crude oil and liquids-rich natural gas production. EOG has placed an emphasis on applying its horizontal drilling and completion expertise to unconventional crude oil and liquids-rich reservoirs.

During 2018, EOG continued to focus on increasing drilling, completion and operating efficiencies gained in prior years. In addition, EOG continued to evaluate certain potential crude oil and liquids-rich natural gas exploration and development prospects and to look for opportunities to add drilling inventory through leasehold acquisitions, farm-ins, exchanges or tactical acquisitions. On a volumetric basis, as calculated using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet of natural gas, crude oil and condensate and NGL production accounted for approximately 77% of United States production during 2018 and 2017. During 2018, drilling and completion activities occurred primarily in the Eagle Ford play, Delaware Basin play and Rocky Mountain area. EOG's major producing areas in the United States are in New Mexico, North Dakota, Texas, Utah and Wyoming.

Trinidad. In Trinidad, EOG continued to deliver natural gas under existing supply contracts. Several fields in the South East Coast Consortium (SECC) Block, Modified U(a) Block, Block 4(a), Modified U(b) Block, the Banyan Field and the Sercan Area have been developed and are producing natural gas which is sold to the National Gas Company of Trinidad and Tobago Limited and its subsidiary and crude oil and condensate which is sold to the Petroleum Company of Trinidad and Tobago Limited and its successor, Heritage Petroleum Company Limited. In 2018, EOG conducted an ocean bottom nodal seismic survey in the SECC Block and the Pelican Field and continued to process and review the initial data.

Other International. In the Sichuan Basin, Sichuan Province, China, EOG entered 2018 with two drilled uncompleted wells and completed both wells. In addition, EOG drilled five natural gas wells and completed one of those wells in 2018 as part of the continuing development of the Bajiaochang Field, which natural gas is sold under a long-term contract to PetroChina.

In the U.K., EOG produced crude oil from its 100% working interest East Irish Sea Conwy development project. EOG completed the sale of all of its interest in EOG Resources United Kingdom Limited during the fourth quarter of 2018. EOG no longer has any presence in the U.K.

EOG continues to evaluate other select crude oil and natural gas opportunities outside the United States, primarily by pursuing exploitation opportunities in countries where indigenous crude oil and natural gas reserves have been identified.

Capital Structure

One of management's key strategies is to maintain a strong balance sheet with a consistently below average debt-to-total capitalization ratio as compared to those in EOG's peer group. EOG's debt-to-total capitalization ratio was 24% at December 31, 2018 and 28% at December 31, 2017. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

On October 1, 2018, EOG repaid upon maturity the $350 million aggregate principal amount of its 6.875% Senior Notes due 2018.

During 2018, EOG funded $6.6 billion ($411 million of which was non-cash) in exploration and development and other property, plant and equipment expenditures (excluding asset retirement obligations), repaid $350 million aggregate principal amount of long-term debt, paid $438 million in dividends to common stockholders and purchased $63 million of treasury stock in connection with stock compensation plans, primarily by utilizing net cash provided from its operating activities and net proceeds of $227 million from the sale of assets.

Total anticipated 2019 capital expenditures are estimated to range from approximately $6.1 billion to $6.5 billion, excluding acquisitions and non-cash exchanges. The majority of 2019 expenditures will be focused on United States crude oil drilling activities. EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program and other uncommitted credit facilities, bank borrowings, borrowings under its $2.0 billion senior unsecured revolving credit facility, joint development agreements and similar agreements and equity and debt offerings.

Management continues to believe EOG has one of the strongest prospect inventories in EOG's history. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer incremental exploration and/or production opportunities.

Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2018, should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning on page F-1.

Operating Revenues and Other

During 2018, operating revenues increased $6,067 million, or 54%, to $17,275 million from $11,208 million in 2017. Total wellhead revenues, which are revenues generated from sales of EOG's production of crude oil and condensate, NGLs and natural gas, increased $4,039 million, or 51%, to $11,946 million in 2018 from $7,907 million in 2017. Revenues from the sales of crude oil and condensate and NGLs in 2018 were approximately 89% of total wellhead revenues compared to 88% in 2017. During 2018, EOG recognized net losses on the mark-to-market of financial commodity derivative contracts of $166 million compared to net gains of $20 million in 2017. Gathering, processing and marketing revenues increased $1,932 million during 2018, to $5,230 million from $3,298 million in 2017. Net gains on asset dispositions of $175 million in 2018 were primarily as a result of exchanges of producing properties and acreage in Texas and sales of producing properties and acreage in the United Kingdom, Texas and the Rocky Mountain area compared to net losses on asset dispositions of $99 million in 2017.

Wellhead volume and price statistics for the years ended December 31, 2018, 2017 and 2016 were as follows:

Year Ended December 31	2018	2017	2016
Crude Oil and Condensate Volumes (MBbld) (1)			
United States	394.8	335.0	278.3
Trinidad	0.8	0.9	0.8
Other International (2)	4.3	0.8	3.4
Total	399.9	336.7	282.5
Average Crude Oil and Condensate Prices ($/Bbl) (3)			
United States	$65.16	$50.91	$41.84
Trinidad	57.26	42.30	33.76
Other International (2)	71.45	57.20	36.72
Composite	65.21	50.91	41.76
Natural Gas Liquids Volumes (MBbld) (1)			
United States	116.1	88.4	81.6
Other International (2)	—	—	—
Total	116.1	88.4	81.6
Average Natural Gas Liquids Prices ($/Bbl) (3)			
United States	$26.60	$22.61	$14.63
Other International (2)	—	—	—
Composite	26.60	22.61	14.63
Natural Gas Volumes (MMcfd) (1)			
United States	923	765	810
Trinidad	266	313	340
Other International (2)	30	25	25
Total	1,219	1,103	1,175
Average Natural Gas Prices ($/Mcf) (3)			
United States	$2.88	$2.20	$1.60
Trinidad	2.94	2.38	1.88
Other International (2)	4.08	3.89	3.64
Composite	2.92 (4)	2.29	1.73
Crude Oil Equivalent Volumes (MBoed) (5)			
United States	664.7	551.0	494.9
Trinidad	45.1	53.0	57.5
Other International (2)	9.4	4.9	7.6
Total	719.2	608.9	560.0
Total MMBoe (5)	262.5	222.3	205.0

(1) Thousand barrels per day or million cubic feet per day, as applicable.

(2) Other International includes EOG's United Kingdom, China, Canada and Argentina operations. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

(3) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments (see Note 12 to Consolidated Financial Statements).

(4) Includes a positive revenue adjustment of $0.44 per Mcf related to the adoption of ASU 2014-09, "Revenue From Contracts with Customers" (ASU 2014-09) (see Note 1 to the Consolidated Financial Statements). In connection with the adoption of ASU 2014-09, EOG presents natural gas processing fees related to certain processing and marketing agreements as Gathering and Processing Costs, instead of as a deduction to Natural Gas revenues.

(5) Thousand barrels of oil equivalent per day or million barrels of oil equivalent, as applicable; includes crude oil and condensate, NGLs and natural gas. Crude oil equivalent volumes are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet of natural gas. MMBoe is calculated by multiplying the MBoed amount by the number of days in the period and then dividing that amount by one thousand.

2018 compared to 2017. Wellhead crude oil and condensate revenues in 2018 increased $3,261 million, or 52%, to $9,517 million from $6,256 million in 2017, due primarily to a higher composite average wellhead crude oil and condensate price ($2,088 million) and an increase in production ($1,173 million). EOG's composite wellhead crude oil and condensate price for 2018 increased 28% to $65.21 per barrel compared to $50.91 per barrel in 2017. Wellhead crude oil and condensate production in 2018 increased 19% to 400 MBbld as compared to 337 MBbld in 2017. The increased production was primarily in the Permian Basin and the Eagle Ford.

NGL revenues in 2018 increased $398 million, or 55%, to $1,127 million from $729 million in 2017 primarily due to an increase in production ($229 million) and a higher composite average wellhead NGL price ($169 million). EOG's composite average wellhead NGL price increased 18% to $26.60 per barrel in 2018 compared to $22.61 per barrel in 2017. NGL production in 2018 increased 31% to 116 MBbld as compared to 88 MBbld in 2017. The increased production was primarily in the Permian Basin and the Eagle Ford.

Wellhead natural gas revenues in 2018 increased $380 million, or 41%, to $1,302 million from $922 million in 2017, primarily due to a higher composite wellhead natural gas price ($282 million) and an increase in wellhead natural gas deliveries ($98 million). EOG's composite average wellhead natural gas price increased 28% to $2.92 per Mcf in 2018 compared to $2.29 per Mcf in 2017. This increase in composite wellhead natural gas prices includes a positive revenue adjustment of $0.44 per Mcf related to the adoption of ASU 2014-09. Natural gas deliveries in 2018 increased 11% to 1,219 MMcfd as compared to 1,103 MMcfd in 2017. The increase in production was primarily due to increased production in the United States (158 MMcfd), partially offset by decreased production in Trinidad (47 MMcfd). The increased production in the United States was due primarily to increased production of associated gas in the Permian Basin and Rocky Mountain area and higher volumes in the Marcellus Shale. The decrease in Trinidad was primarily attributable to higher contractual deliveries in 2017.

During 2018, EOG recognized net losses on the mark-to-market of financial commodity derivative contracts of $166 million, which included net cash paid for settlements of crude oil and natural gas financial derivative contracts of $259 million. During 2017, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $20 million, which included net cash received from settlements of crude oil and natural gas financial derivative contracts of $7 million.

Gathering, processing and marketing revenues are revenues generated from sales of third-party crude oil, NGLs and natural gas, as well as gathering fees associated with gathering third-party natural gas and revenues from sales of EOG-owned sand. Purchases and sales of third-party crude oil and natural gas may be utilized in order to balance firm transportation capacity with production in certain areas and to utilize excess capacity at EOG-owned facilities. EOG sells sand in order to balance the timing of firm purchase agreements with completion operations and to utilize excess capacity at EOG-owned facilities. Marketing costs represent the costs to purchase third-party crude oil, natural gas and sand and the associated transportation costs, as well as costs associated with EOG-owned sand sold to third parties.

Gathering, processing and marketing revenues less marketing costs in 2018 increased $59 million compared to 2017, primarily due to higher margins on crude oil and condensate marketing activities.

2017 compared to 2016. Wellhead crude oil and condensate revenues in 2017 increased $1,939 million, or 45%, to $6,256 million from $4,317 million in 2016, due primarily to a higher composite average wellhead crude oil and condensate price ($1,124 million) and an increase in production ($815 million). EOG's composite wellhead crude oil and condensate price for 2017 increased 22% to $50.91 per barrel compared to $41.76 per barrel in 2016. Wellhead crude oil and condensate deliveries in 2017 increased 19% to 337 MBbld as compared to 283 MBbld in 2016. The increased production was primarily due to higher production in the Permian Basin and Rocky Mountain area.

NGL revenues in 2017 increased $292 million, or 67%, to $729 million from $437 million in 2016 primarily due to a higher composite wellhead NGL price ($257 million) and an increase in production ($35 million). EOG's composite average wellhead NGL price increased 55% to $22.61 per barrel in 2017 compared to $14.63 per barrel in 2016. The increased production was primarily due to higher production in the Permian Basin and Rocky Mountain area, partially offset by decreased production in the Fort Worth Barnett Shale, largely resulting from 2016 asset sales in this region.

Wellhead natural gas revenues in 2017 increased $180 million, or 24%, to $922 million from $742 million in 2016, primarily due to a higher composite wellhead natural gas price ($227 million), partially offset by a decrease in wellhead natural gas deliveries ($47 million). EOG's composite average wellhead natural gas price increased 32% to $2.29 per Mcf in 2017 compared to $1.73 per Mcf in 2016. Natural gas deliveries in 2017 decreased 6% to 1,103 MMcfd as compared to 1,175 MMcfd in 2016. The decrease in production was primarily due to decreased production in the United States (45 MMcfd) and Trinidad (27 MMcfd). The decreased production in the United States was due primarily to lower volumes in the Fort Worth Barnett Shale, Upper Gulf Coast and South Texas areas, largely resulting from 2016 asset sales in these regions, partially offset by increased production of associated gas in the Permian Basin and Rocky Mountain area and from the 2016 mergers and related asset purchase transactions with Yates Petroleum Corporation and other affiliated entities (collectively, the Yates Entities). The decrease in Trinidad was primarily attributable to higher contractual deliveries in 2016.

During 2017, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $20 million, which included net cash received from settlements of crude oil and natural gas financial derivative contracts of $7 million. During 2016, EOG recognized net losses on the mark-to-market of financial commodity derivative contracts of $100 million, which included net cash paid for settlements of crude oil and natural gas financial derivative contracts of $22 million.

Gathering, processing and marketing revenues less marketing costs in 2017 increased $9 million compared to 2016, primarily due to higher margins on natural gas and NGL marketing activities ($16 million), partially offset by lower margins on sand sales ($9 million).

Operating and Other Expenses

2018 compared to 2017. During 2018, operating expenses of $12,806 million were $2,524 million higher than the $10,282 million incurred during 2017. The following table presents the costs per barrel of oil equivalent (Boe) for the years ended December 31, 2018 and 2017:

	2018	2017
Lease and Well	$4.89	$4.70
Transportation Costs	2.85	3.33
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	12.65	14.83
Other Property, Plant and Equipment	0.44	0.51
General and Administrative (G&A)	1.63	1.95
Net Interest Expense	0.93	1.23
Total (1)	$23.39	$26.55

(1) Total excludes gathering and processing costs, exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and net interest expense for 2018 compared to 2017 are set forth below. See "Operating Revenues and Other" above for a discussion of production volumes.

Lease and well expenses include expenses for EOG-operated properties, as well as expenses billed to EOG from other operators where EOG is not the operator of a property. Lease and well expenses can be divided into the following categories: costs to operate and maintain crude oil and natural gas wells, the cost of workovers and lease and well administrative expenses. Operating and maintenance costs include, among other things, pumping services, salt water disposal, equipment repair and maintenance, compression expense, lease upkeep and fuel and power. Workovers are operations to restore or maintain production from existing wells.

Each of these categories of costs individually fluctuates from time to time as EOG attempts to maintain and increase production while maintaining efficient, safe and environmentally responsible operations. EOG continues to increase its operating activities by drilling new wells in existing and new areas. Operating and maintenance costs within these existing and new areas, as well as the costs of services charged to EOG by vendors, fluctuate over time.

Lease and well expenses of $1,283 million in 2018 increased $238 million from $1,045 million in 2017 primarily due to higher operating and maintenance costs ($171 million), higher workover expenditures ($44 million) and higher lease and well administrative expenses ($41 million), all in the United States, partially offset by lower operating and maintenance costs in the United Kingdom ($18 million). Lease and well expenses increased in the United States primarily due to increased operating activities resulting in increased production.

Transportation costs represent costs associated with the delivery of hydrocarbon products from the lease to a downstream point of sale. Transportation costs include transportation fees, the cost of compression (the cost of compressing natural gas to meet pipeline pressure requirements), dehydration (the cost associated with removing water from natural gas to meet pipeline requirements), gathering fees and fuel costs.

Transportation costs of $747 million in 2018 increased $7 million from $740 million in 2017 primarily due to increased transportation costs in the Permian Basin ($116 million), partially offset by decreased transportation costs in the Barnett Shale ($52 million), the Eagle Ford ($31 million) and the Rocky Mountain area ($25 million).

DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method. EOG's DD&A rate and expense are the composite of numerous individual DD&A group calculations. There are several factors that can impact EOG's composite DD&A rate and expense, such as field production profiles, drilling or acquisition of new wells, disposition of existing wells and reserve revisions (upward or downward) primarily related to well performance, economic factors and impairments. Changes to these factors may cause EOG's composite DD&A rate and expense to fluctuate from period to period. DD&A of the cost of other property, plant and equipment is generally calculated using the straight-line depreciation method over the useful lives of the assets.

DD&A expenses in 2018 increased $26 million to $3,435 million from $3,409 million in 2017. DD&A expenses associated with oil and gas properties in 2018 were $24 million higher than in 2017 primarily due to an increase in production in the United States ($647 million) and the United Kingdom ($21 million), partially offset by lower unit rates in the United States ($625 million) and a decrease in production in Trinidad ($16 million). Unit rates in the United States decreased primarily due to upward reserve revisions and reserves added at lower costs as a result of increased efficiencies.

G&A expenses of $427 million in 2018 decreased $7 million from $434 million in 2017 primarily due to decreased professional, legal and other services ($24 million); partially offset by increased employee-related expenses resulting from expanded operations ($15 million) and increased information systems costs ($10 million).

Net interest expense of $245 million in 2018 was $29 million lower than 2017 primarily due to repayment of the $600 million aggregate principal amount of 5.875% Senior Notes due 2017 in September 2017 ($25 million) and the $350 million aggregate principal amount of 6.875% Senior Notes due 2018 in October 2018 ($6 million), partially offset by a decrease in capitalized interest ($3 million).

Gathering and processing costs represent operating and maintenance expenses and administrative expenses associated with operating EOG's gathering and processing assets and beginning January 1, 2018, natural gas processing fees from third parties. EOG pays third parties to process a portion of its natural gas production to extract NGLs. See Note 1 to the Consolidated Financial Statements for discussion related to EOG's adoption of ASU 2014-09.

Gathering and processing costs increased $288 million to $437 million in 2018 compared to $149 million in 2017 primarily due to the adoption of ASU 2014-09 ($204 million) and increased operating costs in the Permian Basin ($32 million), the United Kingdom ($28 million) and the Eagle Ford ($25 million).

Exploration costs of $149 million in 2018 increased $4 million from $145 million in 2017 primarily due to increased general and administrative expenses in the United States ($7 million), partially offset by decreased geological and geophysical expenditures in Trinidad ($5 million).

Impairments include amortization of unproved oil and gas property costs as well as impairments of proved oil and gas properties; other property, plant and equipment; and other assets. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. Unproved properties with individually significant acquisition costs are reviewed individually for impairment. When circumstances indicate that a proved property may be impaired, EOG compares expected undiscounted future cash flows at a DD&A group level to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated by using the Income Approach described in the Fair Value Measurement Topic of the Financial Accounting Standards Board's Accounting Standards Codification (ASC). In certain instances, EOG utilizes accepted offers from third-party purchasers as the basis for determining fair value.

The following table represents impairments for the years ended December 31, 2018 and 2017 (in millions):

	2018	2017
Proved properties	$121	$224
Unproved properties	173	211
Other assets	49	28
Other property, plant and equipment	—	16
Inventories	4	—
Total	$347	$479

Impairments of proved properties were primarily due to the write-down to fair value of legacy natural gas assets in 2018 and 2017.

Taxes other than income include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Severance/production taxes are generally determined based on wellhead revenues, and ad valorem/property taxes are generally determined based on the valuation of the underlying assets.

Taxes other than income in 2018 increased $227 million to $772 million (6.5% of wellhead revenues) from $545 million (6.9% of wellhead revenues) in 2017. The increase in taxes other than income was primarily due to increases in severance/production taxes ($190 million) primarily as a result of increased wellhead revenues and an increase in ad valorem/property taxes ($33 million), both in the United States.

Other income, net, was $17 million in 2018 compared to other income, net, of $9 million in 2017. The increase of $8 million in 2018 was primarily due to a decrease in deferred compensation expense ($12 million) and an increase in interest income ($4 million); partially offset by an increase in foreign currency transaction losses ($15 million).

EOG recognized an income tax provision of $822 million in 2018 compared to an income tax benefit of $1,921 million in 2017, primarily due to the absence of certain 2017 tax benefits related to the Tax Cuts and Jobs Act (TCJA) and higher pretax income. The most significant impact of the TCJA on EOG was the reduction in the statutory income tax rate from 35% to 21% which required the existing net United States federal deferred income tax liability to be remeasured resulting in the recognition of an income tax benefit in 2017 of approximately $2.2 billion. The net effective tax rate for 2018 increased to 19% from (291%) in the prior year, primarily due to the absence of the TCJA tax benefits.

2017 compared to 2016. During 2017, operating expenses of $10,282 million were $1,406 million higher than the $8,876 million incurred during 2016. The following table presents the costs per barrel of oil equivalent (Boe) for the years ended December 31, 2017 and 2016:

	2017	2016
Lease and Well	$4.70	$4.53
Transportation Costs	3.33	3.73
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	14.83	16.77
Other Property, Plant and Equipment	0.51	0.57
General and Administrative (G&A)	1.95	1.93
Net Interest Expense	1.23	1.37
Total [(1)]	$26.55	$28.90

(1) Total excludes gathering and processing costs, exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and net interest expense for 2017 compared to 2016 are set forth below. See "Operating Revenues and Other" above for a discussion of production volumes.

Lease and well expenses of $1,045 million in 2017 increased $118 million from $927 million in 2016 primarily due to higher operating and maintenance costs in the United States ($71 million) and the United Kingdom ($30 million) and higher workover expenditures in the United States ($21 million). Lease and well expenses increased in the United States primarily due to increased operating activities resulting in increased production.

Transportation costs of $740 million in 2017 decreased $24 million from $764 million in 2016 primarily due to divestitures in the Barnett Shale and Upper Gulf Coast ($85 million) and decreased transportation costs in the Eagle Ford ($8 million) and the United Kingdom ($8 million), partially offset by increased transportation costs related to higher production in the Permian Basin ($47 million) and the Rocky Mountain area ($20 million) and from the 2016 transactions with the Yates Entities ($13 million).

DD&A expenses in 2017 decreased $144 million to $3,409 million from $3,553 million in 2016. DD&A expenses associated with oil and gas properties in 2017 were $141 million lower than in 2016 primarily due to lower unit rates in the United States ($449 million) and Trinidad ($19 million) and a decrease in production in the United Kingdom ($16 million) and Trinidad ($11 million), partially offset by an increase in production in the United States ($354 million). Unit rates in the United States decreased primarily due to upward reserve revisions and reserves added at lower costs as a result of increased efficiencies.

G&A expenses of $434 million in 2017 increased $39 million from $395 million in 2016 primarily due to increased employee-related expenses resulting from expanded operations and from the 2016 transactions with the Yates Entities ($45 million) and increased professional, legal and other services ($30 million), partially offset by 2016 employee related expenses in connection with certain voluntary retirements ($42 million).

Net interest expense of $274 million in 2017 was $8 million lower than 2016 primarily due to repayment of the $600 million aggregate principal amount of 5.875% Senior Notes due 2017 in September 2017 ($11 million), partially offset by a decrease in capitalized interest ($4 million).

Gathering and processing costs increased $26 million to $149 million in 2017 compared to $123 million in 2016 due to increased activities in the Permian Basin ($12 million) and the Rocky Mountain area ($8 million).

Exploration costs of $145 million in 2017 increased $20 million from $125 million in 2016 primarily due to increased geological and geophysical expenditures in Trinidad.

The following table represents impairments for the years ended December 31, 2017 and 2016 (in millions):

	2017	2016
Proved properties	$224	$116
Unproved properties	211	291
Other assets	28	—
Other property, plant and equipment	16	14
Inventories	—	61
Firm commitment contracts	—	138
Total	$479	$620

Impairments of proved properties were primarily due to the write-down to fair value of divested legacy natural gas assets in 2017 and 2016. EOG recognized additional impairment charges in 2016 of $61 million related to obsolete inventory and $138 million related to firm commitment contracts related to divested Haynesville natural gas assets.

Taxes other than income in 2017 increased $195 million to $545 million (6.9% of wellhead revenues) from $350 million (6.4% of wellhead revenues) in 2016. The increase in taxes other than income was primarily due to increases in severance/production taxes ($171 million) and in ad valorem/property taxes ($18 million), both primarily as a result of increased wellhead revenues in the United States.

Other income, net, was $9 million in 2017 compared to other expense, net, of $51 million in 2016. The increase of $60 million was primarily due to an increase in foreign currency transaction gains in 2017 ($49 million) and interest income ($5 million).

EOG recognized an income tax benefit of $1,921 million in 2017 compared to an income tax benefit of $461 million in 2016, primarily due to the enactment of the TCJA in December 2017. The most significant impact of the TCJA on EOG was the reduction in the statutory income tax rate from 35% to 21%, which required the existing net United States federal deferred income tax liability to be remeasured, resulting in the recognition of an income tax benefit of approximately $2.2 billion. Due largely to this tax rate reduction, the net effective tax rate for 2017 decreased to (291)% from 30% in the prior year.

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2018, were funds generated from operations and proceeds from asset sales. The primary uses of cash were funds used in operations; exploration and development expenditures; other property, plant and equipment expenditures; dividend payments to stockholders; repayments of debt; and purchases of treasury stock in connection with stock compensation plans.

2018 compared to 2017. Net cash provided by operating activities of $7,769 million in 2018 increased $3,504 million from $4,265 million in 2017 primarily reflecting an increase in wellhead revenues ($4,039 million), favorable changes in working capital and other assets and liabilities ($758 million) and a favorable change in the cash paid for income taxes ($113 million), partially offset by an increase in cash operating expenses ($746 million) and an unfavorable change in the net cash paid for the settlement of financial commodity derivative contracts ($266 million).

Net cash used in investing activities of $6,170 million in 2018 increased by $2,183 million from $3,987 million in 2017 primarily due to an increase in additions to oil and gas properties ($1,888 million); unfavorable changes in working capital associated with investing activities ($211 million); and an increase in additions to other property, plant and equipment ($64 million).

Net cash used in financing activities of $839 million in 2018 included cash dividend payments ($438 million), repayments of long-term debt ($350 million) and purchases of treasury stock in connection with stock compensation plans ($63 million). Cash provided by financing activities in 2018 included proceeds from stock options exercised and employee stock purchase plan activity ($21 million).

2017 compared to 2016. Net cash provided by operating activities of $4,265 million in 2017 increased $1,906 million from $2,359 million in 2016 primarily reflecting an increase in wellhead revenues ($2,411 million) and a favorable change in the net cash received from the settlement of financial commodity derivative contracts ($30 million), partially offset by an increase in cash operating expenses ($362 million), an increase in net cash paid for income taxes ($228 million), an increase in net cash paid for interest expense ($23 million) and unfavorable changes in working capital and other assets and liabilities ($10 million).

Net cash used in investing activities of $3,987 million in 2017 increased by $2,734 million from $1,253 million in 2016 primarily due to an increase in additions to oil and gas properties ($1,461 million); a decrease in proceeds from asset sales ($892 million); unfavorable changes in working capital associated with investing activities ($246 million); and an increase in additions to other property, plant and equipment ($80 million).

Net cash used in financing activities of $1,036 million in 2017 included repayments of long-term debt ($600 million), cash dividend payments ($387 million) and purchases of treasury stock in connection with stock compensation plans ($63 million). Cash provided by financing activities in 2017 included proceeds from stock options exercised and employee stock purchase plan activity ($21 million).

Total Expenditures

The table below sets out components of total expenditures for the years ended December 31, 2018, 2017 and 2016 (in millions):

	2018	2017	2016
Expenditure Category			
Capital			
Exploration and Development Drilling	$4,935	$3,132	$1,957
Facilities	625	575	375
Leasehold Acquisitions (1)	488	427	3,217
Property Acquisitions (2)	124	73	749
Capitalized Interest	24	27	31
Subtotal	6,196	4,234	6,329
Exploration Costs	149	145	125
Dry Hole Costs	5	5	11
Exploration and Development Expenditures	6,350	4,384	6,465
Asset Retirement Costs	70	56	(20)
Total Exploration and Development Expenditures	6,420	4,440	6,445
Other Property, Plant and Equipment (3)	286	173	109
Total Expenditures	$6,706	$4,613	$6,554

(1) Leasehold acquisitions included $291 million and $256 million related to non-cash property exchanges in 2018 and 2017, respectively, and $3,115 million in 2016 related to the Yates transaction.

(2) Property acquisitions included $71 million and $26 million related to non-cash property exchanges in 2018 and 2017, respectively, and $735 million in 2016 related to the Yates transaction.

(3) Other property, plant and equipment included $49 million of non-cash additions in 2018 primarily related to a capital lease transaction in the Permian Basin and $17 million in 2016 related to the Yates transaction.

Exploration and development expenditures of $6,350 million for 2018 were $1,966 million higher than the prior year. The increase was primarily due to increased exploration and development drilling expenditures in the United States ($1,932 million) and Other International ($11 million), increased leasehold acquisitions ($61 million), increased property acquisitions ($51 million) and increased facility expenditures ($50 million), partially offset by decreased exploration and development drilling expenditures in Trinidad ($140 million). The 2018 exploration and development expenditures of $6,350 million included $5,546 million in development drilling and facilities, $656 million in exploration, $124 million in property acquisitions and $24 million in capitalized interest. The 2017 exploration and development expenditures of $4,384 million included $3,661 million in development drilling and facilities, $623 million in exploration, $73 million in property acquisitions and $27 million in capitalized interest. The 2016 exploration and development expenditures of $6,465 million included $3,351 million in exploration, $2,334 million in development drilling and facilities, $749 million in property acquisitions and $31 million in capitalized interest.

The level of exploration and development expenditures, including acquisitions, will vary in future periods depending on energy market conditions and other related economic factors. EOG has significant flexibility with respect to financing alternatives and the ability to adjust its exploration and development expenditure budget as circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to its operations, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Derivative Transactions

Commodity Derivative Contracts. Prices received by EOG for its crude oil production generally vary from U.S. New York Mercantile Exchange (NYMEX) West Texas Intermediate prices due to adjustments for delivery location (basis) and other factors. EOG has entered into crude oil basis swap contracts in order to fix the differential between pricing in Midland, Texas, and Cushing, Oklahoma (Midland Differential). Presented below is a comprehensive summary of EOG's Midland Differential basis swap contracts through February 19, 2019. The weighted average price differential expressed in dollars per barrel ($/Bbl) represents the amount of reduction to Cushing, Oklahoma, prices for the notional volumes expressed in barrels per day (Bbld) covered by the basis swap contracts.

Midland Differential Basis Swap Contracts

	Volume (Bbld)	Weighted Average Price Differential ($/Bbl)
2018		
January 1, 2018 through December 31, 2018 (closed)	15,000	$ 1.063
2019		
January 1, 2019 through February 28, 2019 (closed)	20,000	$ 1.075
March 1, 2019 through December 31, 2019	20,000	1.075

EOG has also entered into crude oil basis swap contracts in order to fix the differential between pricing in the U.S. Gulf Coast and Cushing, Oklahoma (Gulf Coast Differential). Presented below is a comprehensive summary of EOG's Gulf Coast Differential basis swap contracts through February 19, 2019. The weighted average price differential expressed in $/Bbl represents the amount of addition to Cushing, Oklahoma, prices for the notional volumes expressed in Bbld covered by the basis swap contracts.

Gulf Coast Differential Basis Swap Contracts

	Volume (Bbld)	Weighted Average Price Differential ($/Bbl)
2018		
January 1, 2018 through September 30, 2018 (closed)	37,000	$ 3.818
October 1, 2018 through December 31, 2018 (closed)	52,000	3.911
2019		
January 1, 2019 through February 28, 2019 (closed)	13,000	$ 5.572
March 1, 2019 through December 31, 2019	13,000	5.572

Presented below is a comprehensive summary of EOG's crude oil price swap contracts through February 19, 2019, with notional volumes expressed in Bbld and prices expressed in $/Bbl.

Crude Oil Price Swap Contracts

	Volume (Bbld)	Weighted Average Price ($/Bbl)
2018		
January 1, 2018 through November 30, 2018 (closed)	134,000	$ 60.04

On November 20, 2018, EOG entered into crude oil price swap contracts for the period December 1, 2018 through December 31, 2018, with notional volumes of 134,000 Bbld at an average price of $53.75 per Bbl. These contracts offset the crude oil price swap contracts for the same time period with notional volumes of 134,000 Bbld at an average price of $60.04 per Bbl. The net cash EOG received for settling these contracts was $26.1 million. The offsetting contracts are excluded from the above table.

Presented below is a comprehensive summary of EOG's natural gas price swap contracts through February 19, 2019, with notional volumes expressed in million British thermal units (MMBtu) per day (MMBtud) and prices expressed in dollars per MMBtu ($/MMBtu).

Natural Gas Price Swap Contracts

	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2018		
March 1, 2018 through November 30, 2018 (closed)	35,000	$ 3.00

EOG has sold call options which establish a ceiling price for the sale of notional volumes of natural gas as specified in the call option contracts. The call options require that EOG pay the difference between the call option strike price and either the average or last business day NYMEX Henry Hub natural gas price for the contract month (Henry Hub Index Price) in the event the Henry Hub Index Price is above the call option strike price.

In addition, EOG has purchased put options which establish a floor price for the sale of notional volumes of natural gas as specified in the put option contracts. The put options grant EOG the right to receive the difference between the put option strike price and the Henry Hub Index Price in the event the Henry Hub Index Price is below the put option strike price. Presented below is a comprehensive summary of EOG's natural gas call and put option contracts through February 19, 2019, with notional volumes expressed in MMBtud and prices expressed in $/MMBtu.

Natural Gas Option Contracts

	Call Options Sold		Put Options Purchased	
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2018				
March 1, 2018 through November 30, 2018 (closed)	120,000	$ 3.38	96,000	$ 2.94

Financing

EOG's debt-to-total capitalization ratio was 24% at December 31, 2018, compared to 28% at December 31, 2017. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

At December 31, 2018 and 2017, respectively, EOG had outstanding $6,040 million and $6,390 million aggregate principal amount of senior notes which had estimated fair values of $6,027 million and $6,602 million, respectively. The estimated fair value was based upon quoted market prices and, where such prices were not available, other observable inputs regarding interest rates available to EOG at year-end. EOG's debt is at fixed interest rates. While changes in interest rates affect the fair value of EOG's senior notes, such changes do not expose EOG to material fluctuations in earnings or cash flow.

During 2018, EOG funded its capital program primarily by utilizing cash provided by operating activities, proceeds from asset sales and cash provided by borrowings from its commercial paper program. While EOG maintains a $2.0 billion commercial paper program, the maximum outstanding at any time during 2018 was $208 million, and the amount outstanding at year-end was zero. There were no amounts outstanding under uncommitted credit facilities during 2018. The average borrowings outstanding under the commercial paper program were $8 million during the year 2018. EOG considers this excess availability, which is backed by its $2.0 billion senior unsecured revolving credit facility described in Note 2 to Consolidated Financial Statements, to be sufficient to meet its ongoing operating needs.

Contractual Obligations

The following table summarizes EOG's contractual obligations at December 31, 2018, (in thousands):

Contractual Obligations (1) (2)	Total	2019	2020-2021	2022-2023	2024 & Beyond
Current and Long-Term Debt	$6,040,000	$900,000	$1,750,000	$1,250,000	$2,140,000
Capital Lease	71,571	13,384	27,560	17,529	13,098
Non-Cancelable Operating Leases	555,692	175,787	218,995	90,608	70,302
Interest Payments on Long-Term Debt and Capital Lease	1,276,530	213,776	308,379	227,185	527,190
Transportation and Storage Service Commitments (3)	3,781,178	898,491	1,370,060	880,057	632,570
Drilling Rig Commitments (4)	391,459	262,404	126,398	2,657	—
Seismic Purchase Obligations	6,898	6,898	—	—	—
Fracturing Services Obligations	1,048,517	421,873	460,088	164,041	2,515
Other Purchase Obligations	1,024,301	385,525	237,771	175,250	225,755
Total Contractual Obligations	$14,196,146	$3,278,138	$4,499,251	$2,807,327	$3,611,430

(1) This table does not include the liability for unrecognized tax benefits, EOG's pension or postretirement benefit obligations or liability for dismantlement, abandonment and asset retirement obligations (see Notes 6, 7 and 15, respectively, to Consolidated Financial Statements). These amounts are excluded because they are subject to estimates and the timing of settlement is unknown.

(2) This table does not include the liability for commitments to purchase fixed quantities of crude oil and natural gas. The amounts are excluded because they are variable and based on future commodity prices. At December 31, 2018, EOG is committed to purchase 3.6 MMBbls of crude oil and 15 Bcf of natural gas in 2019.

(3) Amounts shown are based on current transportation and storage rates and the foreign currency exchange rates used to convert Canadian dollars into United States dollars at December 31, 2018. Management does not believe that any future changes in these rates before the expiration dates of these commitments will have a material adverse effect on the financial condition or results of operations of EOG.

(4) Amounts shown represent minimum future expenditures for drilling rig services. EOG's expenditures for drilling rig services will exceed such minimum amounts to the extent EOG utilizes the drilling rigs subject to a particular contractual commitment for a period greater than the period set forth in the governing contract or if EOG utilizes drilling rigs in addition to the drilling rigs subject to the particular contractual commitment (for example, pursuant to the exercise of an option to utilize additional drilling rigs provided for in the governing contract).

Off-Balance Sheet Arrangements

EOG does not participate in financial transactions that generate relationships with unconsolidated entities or financial partnerships. Such entities or partnerships, often referred to as variable interest entities (VIE) or special purpose entities (SPE), are generally established for the purpose of facilitating off-balance sheet arrangements or other limited purposes. EOG was not involved in any unconsolidated VIE or SPE financial transactions or any other "off-balance sheet arrangement" (as defined in Item 303(a)(4)(ii) of Regulation S-K) during any of the periods covered by this report and currently has no intention of participating in any such transaction or arrangement in the foreseeable future.

Foreign Currency Exchange Rate Risk

During 2018, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Trinidad, China and Canada and, through November 2018, the U.K. The foreign currency most significant to EOG's operations during 2018 was the British pound. EOG continues to monitor the foreign currency exchange rates of countries in which it is currently conducting business and may implement measures to protect against foreign currency exchange rate risk.

Outlook

Pricing. Crude oil and natural gas prices have been volatile, and this volatility is expected to continue. As a result of the many uncertainties associated with the world political environment, worldwide supplies of, and demand for, crude oil and condensate, NGL and natural gas, the availabilities of other worldwide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, EOG is unable to predict what changes may occur in crude oil and condensate, NGLs, natural gas, ammonia and methanol prices in the future. The market price of crude oil and condensate, NGLs and natural gas in 2019 will impact the amount of cash generated from EOG's operating activities, which will in turn impact EOG's financial position. As of February 19, 2019, the average 2019 NYMEX crude oil and natural gas prices were $57.15 per barrel and $2.89 per MMBtu, respectively, representing a decrease of 12% for crude oil and a decrease of 6% for natural gas from the average NYMEX prices in 2018. See ITEM 1A, Risk Factors.

Based on EOG's tax position, EOG's price sensitivity (exclusive of basis swaps) in 2019 for each $1.00 per barrel increase or decrease in wellhead crude oil and condensate price, combined with the estimated change in NGL price, is approximately $133 million for net income and $173 million for pretax cash flows from operating activities. Based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2019 for which prices have not been determined under long-term marketing contracts, EOG's price sensitivity for each $0.10 per Mcf increase or decrease in wellhead natural gas price is approximately $29 million for net income and $37 million for pretax cash flows from operating activities. For information regarding EOG's crude oil and natural gas financial commodity derivative contracts through February 19, 2019, see "Derivative Transactions" above.

Capital. EOG plans to continue to focus a substantial portion of its exploration and development expenditures in its major producing areas in the United States. In particular, EOG will be focused on United States crude oil drilling activity in its Eagle Ford, Delaware Basin and Rocky Mountain area where it generates its highest rates-of-return. To further enhance the economics of these plays, EOG expects to continue to improve well performance and lower drilling and completion costs through efficiency gains and lower service costs.

The total anticipated 2019 capital expenditures of approximately $6.1 billion to $6.5 billion, excluding acquisitions and non-cash exchanges, is structured to maintain EOG's strategy of capital discipline by funding its exploration, development and exploitation activities primarily from available internally generated cash flows and cash on hand. EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program and other uncommitted credit facilities, bank borrowings, borrowings under its $2.0 billion senior unsecured revolving credit facility and equity and debt offerings.

Operations. In 2019, both total production and total crude oil production are expected to increase from 2018 levels. In 2019, EOG expects to continue to focus on reducing operating costs through efficiency improvements.

Summary of Critical Accounting Policies

EOG prepares its financial statements and the accompanying notes in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. EOG identifies certain accounting policies as critical based on, among other things, their impact on the portrayal of EOG's financial condition, results of operations or liquidity, and the degree of difficulty, subjectivity and complexity in their application. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management routinely discusses the development, selection and disclosure of each of the critical accounting policies. Following is a discussion of EOG's most critical accounting policies:

Proved Oil and Gas Reserves

EOG's engineers estimate proved oil and gas reserves in accordance with United States Securities and Exchange Commission (SEC) regulations, which directly impact financial accounting estimates, including depreciation, depletion and amortization and impairments of proved properties and related assets. Proved reserves represent estimated quantities of crude oil and condensate, NGLs 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 existing at the time the estimates were made. The process of estimating quantities of proved oil and gas reserves is complex, requiring significant subjective decisions in the evaluation of available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. For related discussion, see ITEM 1A, Risk Factors, and "Supplemental Information to Consolidated Financial Statements."

Oil and Gas Exploration Costs

EOG accounts for its crude oil and natural gas exploration and production activities under the successful efforts method of accounting. Oil and gas exploration costs, other than the costs of drilling exploratory wells, are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether EOG has discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of EOG's calculation of depreciation, depletion and amortization expense, and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease, respectively.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Oil and gas properties are grouped in accordance with the provisions of the Extractive Industries - Oil and Gas Topic of the ASC. The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Depreciation, depletion and amortization rates are updated quarterly to reflect the addition of capital costs, reserve revisions (upwards or downwards) and additions, property acquisitions and/or property dispositions and impairments.

Depreciation and amortization of other property, plant and equipment is calculated on a straight-line basis over the estimated useful life of the asset.

Impairments

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. Unproved properties with individually significant acquisition costs are reviewed individually for impairment. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

When circumstances indicate that proved oil and gas properties may be impaired, EOG compares expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows, based on EOG's estimates of (and assumptions regarding) future crude oil and natural gas prices, operating costs, development expenditures, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic of the ASC. In certain instances, EOG utilizes accepted offers from third-party purchasers as the basis for determining fair value. Estimates of undiscounted future cash flows require significant judgment, and the assumptions used in preparing such estimates are inherently uncertain. In addition, such assumptions and estimates are reasonably likely to change in the future.

Crude oil and natural gas prices have exhibited significant volatility in the past, and EOG expects that volatility to continue in the future. During the five years ended December 31, 2018, West Texas Intermediate crude oil spot prices have fluctuated from approximately $26.19 per barrel to $107.95 per barrel, and Henry Hub natural gas spot prices have ranged from approximately $1.49 per MMBtu to $8.15 per MMBtu. EOG uses the five-year NYMEX futures strip for West Texas Intermediate crude oil and Henry Hub natural gas (in each case as of the applicable balance sheet date) as a basis to estimate future crude oil and natural gas prices. EOG's proved reserves estimates, including the timing of future production, are also subject to significant assumptions and judgment, and are frequently revised (upwards and downwards) as more information becomes available. Proved reserves are estimated using a trailing 12-month average price, in accordance with SEC rules. In the future, if any combination of crude oil prices, natural gas prices, actual production or operating costs diverge negatively from EOG's current estimates, impairment charges and downward adjustments to our estimated proved reserves may be necessary.

Income Taxes

Income taxes are accounted for using the asset and liability approach. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis. EOG assesses the realizability of deferred tax assets and recognizes valuation allowances as appropriate. Significant assumptions used in estimating future taxable income include future oil and gas prices and levels of capital reinvestment. Changes in such assumptions or changes in tax laws and regulations could materially affect the recognized amounts of valuation allowances.

Stock-Based Compensation

In accounting for stock-based compensation, judgments and estimates are made regarding, among other things, the appropriate valuation methodology to follow in valuing stock compensation awards and the related inputs required by those valuation methodologies. Assumptions regarding expected volatility of EOG's common stock, the level of risk-free interest rates, expected dividend yields on EOG's common stock, the expected term of the awards, expected volatility in the price of shares of EOG's peer companies and other valuation inputs are subject to change. Any such changes could result in different valuations and thus impact the amount of stock-based compensation expense recognized on the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss).

Information Regarding Forward-Looking Statements

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, including, among others, statements and projections regarding EOG's future financial position, operations, performance, business strategy, returns, budgets, reserves, levels of production, capital expenditures, costs and asset sales, statements regarding future commodity prices and statements regarding the plans and objectives of EOG's management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "project," "strategy," "intend," "plan," "target," “aims,” "goal," "may," "will," "should" and "believe" or the negative of those terms or other variations or comparable terminology to identify its forward-looking statements. In particular, statements, express or implied, concerning EOG's future operating results and returns or EOG's ability to replace or increase reserves, increase production, generate returns, replace or increase drilling locations, reduce or otherwise control operating costs and capital expenditures, generate cash flows, pay down or refinance indebtedness or pay and/or increase dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, EOG's forward-looking statements may be affected by known, unknown or currently unforeseen risks, events or circumstances that may be outside EOG's control. Important factors that could cause EOG's actual results to differ materially from the expectations reflected in EOG's forward-looking statements include, among others:

- the timing, extent and duration of changes in prices for, supplies of, and demand for, crude oil and condensate, natural gas liquids, natural gas and related commodities;
- the extent to which EOG is successful in its efforts to acquire or discover additional reserves;
- the extent to which EOG is successful in its efforts to economically develop its acreage in, produce reserves and achieve anticipated production levels from, and maximize reserve recovery from, its existing and future crude oil and natural gas exploration and development projects;
- the extent to which EOG is successful in its efforts to market its crude oil and condensate, natural gas liquids, natural gas and related commodity production;
- the availability, proximity and capacity of, and costs associated with, appropriate gathering, processing, compression, storage, transportation and refining facilities;
- the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights-of-way, and EOG’s ability to retain mineral licenses and leases;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations; climate change and other environmental, health and safety laws and regulations relating to air emissions, disposal of produced water, drilling fluids and other wastes, hydraulic fracturing and access to and use of water; laws and regulations imposing conditions or restrictions on drilling and completion operations and on the transportation of crude oil and natural gas; laws and regulations with respect to derivatives and hedging activities; and laws and regulations with respect to the import and export of crude oil, natural gas and related commodities;
- EOG's ability to effectively integrate acquired crude oil and natural gas properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;
- the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully and economically;
- competition in the oil and gas exploration and production industry for the acquisition of licenses, leases and properties, employees and other personnel, facilities, equipment, materials and services;
- the availability and cost of employees and other personnel, facilities, equipment, materials (such as water and tubulars) and services;

- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation (by EOG or third parties) of production, gathering, processing, refining, compression, storage and transportation facilities;
- the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;
- EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all, and to otherwise satisfy its capital expenditure requirements;
- the extent to which EOG is successful in its completion of planned asset dispositions;
- the extent and effect of any hedging activities engaged in by EOG;

- the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;
- geopolitical factors and political conditions and developments around the world (such as the imposition of tariffs or trade or other economic sanctions, political instability and armed conflict), including in the areas in which EOG operates;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities or losses and liabilities in excess of its insurance coverage;
- acts of war and terrorism and responses to these acts;
- physical, electronic and cybersecurity breaches; and
- the other factors described under ITEM 1A, Risk Factors, on pages 13 through 22 of this Annual Report on Form 10-K and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur, and, if any of such events do, we may not have anticipated the timing of their occurrence or the duration or extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of EOG's forward-looking statements. EOG's forward-looking statements speak only as of the date made, and EOG undertakes no obligation, other than as required by applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by this Item is incorporated by reference from Item 7 of this report, specifically the information set forth under the captions "Derivative Transactions," "Financing," "Foreign Currency Exchange Rate Risk" and "Outlook" in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity."

ITEM 8. Financial Statements and Supplementary Data

The information required by this Item is included in this report as set forth in the "Index to Financial Statements" on page F-1 and is incorporated by reference herein.

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

None.

ITEM 9A. Controls and Procedures

Disclosure Controls and Procedures. EOG's management, with the participation of EOG's principal executive officer and principal financial officer, evaluated the effectiveness of EOG's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of December 31, 2018. EOG's disclosure controls and procedures are designed to provide reasonable assurance that information that is required to be disclosed in the reports EOG files or submits under the Exchange Act is accumulated and communicated to EOG's management, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the United States Securities and Exchange Commission. Based on that evaluation, EOG's principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of

December 31, 2018.

Management's Annual Report on Internal Control over Financial Reporting. EOG's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act). Even an effective system of internal control over financial reporting, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2018. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control - Integrated Framework (2013). Based on this assessment and such criteria, EOG's management believes that EOG's internal control over financial reporting was effective as of December 31, 2018. See also "Management's Responsibility for Financial Reporting" appearing on page F-2 of this report, which is incorporated herein by reference.

The report of EOG's independent registered public accounting firm relating to the consolidated financial statements and effectiveness of internal control over financial reporting is set forth on page F-3 of this report.

There were no changes in EOG's internal control over financial reporting that occurred during the quarter ended December 31, 2018, that have materially affected, or are reasonably likely to materially affect, EOG's internal control over financial reporting.

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

The information required by this Item is incorporated by reference from (i) EOG's Definitive Proxy Statement with respect to its 2019 Annual Meeting of Stockholders to be filed not later than April 30, 2019 and (ii) Item 1 of this report, specifically the information therein set forth under the caption "Executive Officers of the Registrant."

Pursuant to Rule 303A.10 of the New York Stock Exchange and Item 406 of Regulation S-K promulgated under the Securities Exchange Act of 1934, as amended, EOG has adopted a Code of Business Conduct and Ethics for Directors, Officers and Employees (Code of Conduct) that applies to all EOG directors, officers and employees, including EOG's principal executive officer, principal financial officer and principal accounting officer. EOG has also adopted a Code of Ethics for Senior Financial Officers (Code of Ethics) that, along with EOG's Code of Conduct, applies to EOG's principal executive officer, principal financial officer, principal accounting officer and controllers.

You can access the Code of Conduct and Code of Ethics on the "Governance" page under "Investors" on EOG's website at www.eogresources.com, and any EOG stockholder who so requests may obtain a printed copy of the Code of Conduct and Code of Ethics by submitting a written request to EOG's Corporate Secretary.

EOG intends to disclose any amendments to the Code of Conduct or Code of Ethics, and any waivers with respect to the Code of Conduct or Code of Ethics granted to EOG's principal executive officer, principal financial officer, principal accounting officer, any of our controllers or any of our other employees performing similar functions, on its website at www.eogresources.com within four business days of the amendment or waiver. In such case, the disclosure regarding the amendment or waiver will remain available on EOG's website for at least 12 months after the initial disclosure. There have been no waivers granted with respect to EOG's Code of Conduct or Code of Ethics.

ITEM 11. Executive Compensation

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2019 Annual Meeting of Stockholders to be filed not later than April 30, 2019. The Compensation Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the United States Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that EOG specifically incorporates such information by reference into such a filing.

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

The information required by this Item with respect to security ownership of certain beneficial owners and management is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2019 Annual Meeting of Stockholders to be filed not later than April 30, 2019.

In February 2014, EOG's Board of Directors (Board) approved a two-for-one stock split in the form of a stock dividend (payable to stockholders of record as of March 17, 2014, and paid on March 31, 2014) and corresponding adjustments to EOG's equity compensation plans. All share amounts set forth below have been restated to reflect the two-for-one stock split and such adjustments.

Equity Compensation Plan Information

Stock Plans Approved by EOG Stockholders. EOG's stockholders approved the EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan) at the 2008 Annual Meeting of Stockholders in May 2008. At the 2010 Annual Meeting of Stockholders in April 2010 (2010 Annual Meeting), an amendment to the 2008 Plan was approved, pursuant to which the number of shares of common stock available for future grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units, performance stock, performance units and other stock-based awards under the 2008 Plan was increased by an additional 13.8 million shares, to an aggregate maximum of 25.8 million shares plus shares underlying forfeited or canceled grants under the prior stock plans referenced in the 2008 Plan document. At the 2013 Annual Meeting of Stockholders in May 2013, EOG's stockholders approved the Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Amended and Restated 2008 Plan). As more fully discussed in the Amended and Restated 2008 Plan document, the Amended and Restated 2008 Plan, among other things, authorizes an additional 31.0 million shares of EOG common stock for grant under the plan and extends the expiration date of the plan to May 2023. Under the Amended and Restated 2008 Plan, grants may be made to employees and non-employee members of EOG's Board.

Also at the 2010 Annual Meeting, an amendment to the EOG Resources, Inc. Employee Stock Purchase Plan (ESPP) was approved to increase the shares available for grant by 2.0 million shares. The ESPP was originally approved by EOG's stockholders in 2001, and would have expired on July 1, 2011. The amendment also extended the term of the ESPP to December 31, 2019, unless terminated earlier by its terms or by EOG. At the 2018 Annual Meeting of Stockholders, stockholders approved an amendment and restatement of the ESPP to (among other changes) increase the number of shares available for grant by 2.5 million shares and further extend the term of the ESPP to December 31, 2027, unless terminated earlier by its terms or by EOG.

Stock Plans Not Approved by EOG Stockholders. In December 2008, the Board approved the amendment and continuation of the 1996 Deferral Plan as the "EOG Resources, Inc. 409A Deferred Compensation Plan" (Deferral Plan). Under the Deferral Plan (as subsequently amended), payment of up to 50% of base salary and 100% of annual cash bonus, director's fees, vestings of restricted stock units granted to non-employee directors (and dividends credited thereon) under the 2008 Plan and 401(k) refunds (as defined in the Deferral Plan) may be deferred into a phantom stock account. In the phantom stock account, deferrals are treated as if shares of EOG common stock were purchased at the closing stock price on the date of deferral. Dividends are credited quarterly and treated as if reinvested in EOG common stock. Payment of the phantom stock account is made in actual shares of EOG common stock in accordance with the Deferral Plan and the individual's deferral election. A total of 540,000 shares of EOG common stock have been authorized by the Board and registered for issuance under the Deferral Plan. As of December 31, 2018, 327,362 phantom shares had been issued. The Deferral Plan is currently EOG's only stock plan that has not been approved by EOG's stockholders.

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The following table sets forth data for EOG's equity compensation plans aggregated by the various plans approved by EOG's stockholders and those plans not approved by EOG's stockholders, in each case as of December 31, 2018.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (1)	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity Compensation Plans Approved by EOG Stockholders	9,759,247 (2)	$ 96.90	16,243,789 (3)
Equity Compensation Plans Not Approved by EOG Stockholders	273,296 (4)	N/A	212,638 (5)
Total	10,032,543	$ 96.90	16,456,427

(1) The weighted-average exercise price is calculated based solely on the exercise prices of the outstanding stock option and SAR grants and does not reflect shares that will be issued upon the vesting of outstanding restricted stock unit and performance unit grants, or Deferral Plan phantom shares, all of which have no exercise price.

(2) Amount includes 910,880 outstanding restricted stock units, for which shares of EOG common stock will be issued, on a one-for-one basis, upon the vesting of such grants. Amount also includes 539,029 outstanding performance units and assumes, for purposes of this table, (i) the application of a 100% performance multiple upon the completion of each of the remaining performance periods in respect of such performance unit grants and (ii) accordingly, the issuance, on a one-for-one basis, of an aggregate 539,029 shares of EOG common stock upon the vesting of such grants. As more fully discussed in Note 7 to Consolidated Financial Statements, upon the application of the relevant performance multiple at the completion of each of the remaining performance periods in respect of such grants, (A) a minimum of 143,610 and a maximum of 934,448 performance units could be outstanding and (B) accordingly, a minimum of 143,610 and a maximum of 934,448 shares of EOG common stock could be issued upon the vesting of such grants.

(3) Consists of (i) 13,748,078 shares remaining available for issuance under the Amended and Restated 2008 Plan and (ii) 2,495,711 shares remaining available for purchase under the ESPP. Pursuant to the fungible share design of the Amended and Restated 2008 Plan, each share issued as a SAR or stock option under the Amended and Restated 2008 Plan counts as 1.0 share against the aggregate plan share limit, and each share issued as a "full value award" (i.e., as restricted stock, restricted stock units, performance stock or performance units) counts as 2.45 shares against the aggregate plan share limit. Thus, from the 13,748,078 shares remaining available for issuance under the Amended and Restated 2008 Plan, (i) the maximum number of shares we could issue as SAR and stock option awards is 13,748,078 (i.e., if all shares remaining available for issuance under the Amended and Restated 2008 Plan are issued as SAR and stock option awards) and (ii) the maximum number of shares we could issue as full value awards is 5,611,460 (i.e., if all shares remaining available for issuance under the Amended and Restated 2008 Plan are issued as full value awards).

(4)

Consists of shares of EOG common stock to be issued in accordance with the Deferral Plan and participant deferral elections (i.e., in respect of the 273,296 phantom shares issued and outstanding under the Deferral Plan as of December 31, 2018).

(5) Represents phantom shares that remain available for issuance under the Deferral Plan.

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

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2019 Annual Meeting of Stockholders to be filed not later than April 30, 2019.

ITEM 14. Principal Accounting Fees and Services

The information required by this Item is incorporated by reference from EOG's Definitive Proxy Statement with respect to its 2019 Annual Meeting of Stockholders to be filed not later than April 30, 2019.

PART IV

ITEM 15. Exhibits, Financial Statement Schedules

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedule

See "Index to Financial Statements" set forth on page F-1.

(a)(3), (b) Exhibits

See pages E-1 through E-6 for a listing of the exhibits.

ITEM 16. Form 10-K Summary

None.

EOG RESOURCES, INC.
INDEX TO FINANCIAL STATEMENTS

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The following consolidated financial statements of EOG Resources, Inc., together with its subsidiaries (collectively, EOG), were prepared by management, which is responsible for the integrity, objectivity and fair presentation of such financial statements. The statements have been prepared in conformity with generally accepted accounting principles in the United States of America and, accordingly, include some amounts that are based on the best estimates and judgments of management.

EOG's management is also responsible for establishing and maintaining adequate internal control over financial reporting as well as designing and implementing programs and controls to prevent and detect fraud. The system of internal control of EOG is 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 in the United States of America. This system consists of 1) entity level controls, including written policies and guidelines relating to the ethical conduct of business affairs, 2) general computer controls and 3) process controls over initiating, authorizing, recording, processing and reporting transactions. Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error, circumvention of controls or overriding of controls and, therefore, can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

The adequacy of EOG's financial controls and the accounting principles employed by EOG in its financial reporting are under the general oversight of the Audit Committee of the Board of Directors. No member of this committee is an officer or employee of EOG. Moreover, EOG's independent registered public accounting firm and internal auditors have full, free, separate and direct access to the Audit Committee and meet with the committee periodically to discuss accounting, auditing and financial reporting matters.

EOG's management assessed the effectiveness of EOG's internal control over financial reporting as of December 31, 2018. In making this assessment, EOG used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control - Integrated Framework (2013). These criteria cover the control environment, risk assessment process, control activities, information and communication systems, and monitoring activities. Based on this assessment and those criteria, management believes that EOG maintained effective internal control over financial reporting as of December 31, 2018.

Deloitte & Touche LLP, independent registered public accounting firm, was engaged to audit the consolidated financial statements of EOG and audit EOG's internal control over financial reporting and issue a report thereon. In the conduct of the audits, Deloitte & Touche LLP was given unrestricted access to all financial records and related data, including all minutes of meetings of stockholders, the Board of Directors and committees of the Board of Directors. Management believes that all representations made to Deloitte & Touche LLP during the audits were valid and appropriate. Their audits were made in accordance with the standards of the Public Company Accounting Oversight Board (United States). Their report appears on page F-3.

WILLIAM R. THOMAS	TIMOTHY K. DRIGGERS
Chairman of the Board and	Executive Vice President and Chief
Chief Executive Officer	Financial Officer

Houston, Texas
February 26, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the stockholders and the Board of Directors of
EOG Resources, Inc.
Houston, Texas

Opinions on the Financial Statements and Internal Control over Financial Reporting

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

Basis for Opinions

The Company's management is responsible for these 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 the accompanying Management’s Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion 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 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 financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the 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 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 26, 2019

We have served as the Company's auditor since 2002.

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
(In Thousands, Except Per Share Data)

Year Ended December 31	2018	2017	2016
Operating Revenues and Other			
Crude Oil and Condensate	$9,517,440	$6,256,396	$4,317,341
Natural Gas Liquids	1,127,510	729,561	437,250
Natural Gas	1,301,537	921,934	742,152
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	(165,640)	19,828	(99,608)
Gathering, Processing and Marketing	5,230,355	3,298,087	1,966,259
Gains (Losses) on Asset Dispositions, Net	174,562	(99,096)	205,835
Other, Net	89,635	81,610	81,403
Total	17,275,399	11,208,320	7,650,632
Operating Expenses			
Lease and Well	1,282,678	1,044,847	927,452
Transportation Costs	746,876	740,352	764,106
Gathering and Processing Costs	436,973	148,775	122,901
Exploration Costs	148,999	145,342	124,953
Dry Hole Costs	5,405	4,609	10,657
Impairments	347,021	479,240	620,267
Marketing Costs	5,203,243	3,330,237	2,007,635
Depreciation, Depletion and Amortization	3,435,408	3,409,387	3,553,417
General and Administrative	426,969	434,467	394,815
Taxes Other Than Income	772,481	544,662	349,710
Total	12,806,053	10,281,918	8,875,913
Operating Income (Loss)	4,469,346	926,402	(1,225,281)
Other Income (Expense), Net	16,704	9,152	(50,543)
Income (Loss) Before Interest Expense and Income Taxes	4,486,050	935,554	(1,275,824)
Interest Expense			
Incurred	269,549	301,801	313,341
Capitalized	(24,497)	(27,429)	(31,660)
Net Interest Expense	245,052	274,372	281,681
Income (Loss) Before Income Taxes	4,240,998	661,182	(1,557,505)
Income Tax Provision (Benefit)	821,958	(1,921,397)	(460,819)
Net Income (Loss)	$3,419,040	$2,582,579	$(1,096,686)
Net Income (Loss) Per Share			
Basic	$5.93	$4.49	$(1.98)
Diluted	$5.89	$4.46	$(1.98)
Average Number of Common Shares			
Basic	576,578	574,620	553,384
Diluted	580,441	578,693	553,384
Comprehensive Income (Loss)			
Net Income (Loss)	$3,419,040	$2,582,579	$(1,096,686)
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustments	16,816	2,799	12,097
Other, Net of Tax	1,123	(3,086)	2,231
Other Comprehensive Income (Loss)	17,939	(287)	14,328

Comprehensive Income (Loss)	$3,436,979	$2,582,292	$(1,082,358)

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

EOG RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Data)

At December 31	2018	2017
ASSETS		
Current Assets		
Cash and Cash Equivalents	$1,555,634	$834,228
Accounts Receivable, Net	1,915,215	1,597,494
Inventories	859,359	483,865
Assets from Price Risk Management Activities	23,806	7,699
Income Taxes Receivable	427,909	113,357
Other	275,467	242,465
Total	5,057,390	3,279,108
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	57,330,016	52,555,741
Other Property, Plant and Equipment	4,220,665	3,960,759
Total Property, Plant and Equipment	61,550,681	56,516,500
Less: Accumulated Depreciation, Depletion and Amortization	(33,475,162)	(30,851,463)
Total Property, Plant and Equipment, Net	28,075,519	25,665,037
Deferred Income Taxes	777	17,506
Other Assets	800,788	871,427
Total Assets	$33,934,474	$29,833,078
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$2,239,850	$1,847,131
Accrued Taxes Payable	214,726	148,874
Dividends Payable	126,971	96,410
Liabilities from Price Risk Management Activities	—	50,429
Current Portion of Long-Term Debt	913,093	356,235
Other	233,724	226,463
Total	3,728,364	2,725,542
Long-Term Debt	5,170,169	6,030,836
Other Liabilities	1,258,355	1,275,213
Deferred Income Taxes	4,413,398	3,518,214
Commitments and Contingencies (Note 8)		
Stockholders' Equity		
Common Stock, $0.01 Par, 1,280,000,000 Shares Authorized and 580,408,117 Shares and 578,827,768 Shares Issued at December 31, 2018 and 2017, respectively	205,804	205,788
Additional Paid in Capital	5,658,794	5,536,547
Accumulated Other Comprehensive Loss	(1,358)	(19,297)
Retained Earnings	13,543,130	10,593,533
Common Stock Held in Treasury, 385,042 Shares and 350,961 Shares at December 31, 2018 and 2017, respectively	(42,182)	(33,298)
Total Stockholders' Equity	19,364,188	16,283,273
Total Liabilities and Stockholders' Equity	$33,934,474	$29,833,078

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

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In Thousands, Except Per Share Data)

	Common Stock	Additional Paid In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Common Stock Held In Treasury	Total Stockholders' Equity
Balance at December 31, 2015	$205,502	$2,923,461	$ (33,338)	$9,870,816	$(23,406)	$12,943,035
Net Loss	—	—	—	(1,096,686)	—	(1,096,686)
Common Stock Issued for the Yates Transaction	252	2,397,635	—	—	—	2,397,887
Common Stock Issued Under Stock Plans	9	16,388	—	—	—	16,397
Common Stock Dividends Declared, $0.67 Per Share	—	—	—	(376,012)	—	(376,012)
Other Comprehensive Income	—	—	14,328	—	—	14,328
Change in Treasury Stock - Stock Compensation Plans, Net	—	(27,018)	—	—	(48,208)	(75,226)
Excess Tax Benefit from Stock-Based Compensation	—	29,357	—	—	—	29,357
Restricted Stock and Restricted Stock Units, Net	7	(47,509)	—	—	47,502	—
Stock-Based Compensation Expenses	—	128,090	—	—	—	128,090
Treasury Stock Issued as Compensation	—	(19)	—	—	430	411
Balance at December 31, 2016	205,770	5,420,385	(19,010)	8,398,118	(23,682)	13,981,581
Net Income	—	—	—	2,582,579	—	2,582,579
Common Stock Issued Under Stock Plans	7	7,082	—	—	—	7,089
Common Stock Dividends Declared, $0.67 Per Share	—	—	—	(387,164)	—	(387,164)
Other Comprehensive Loss	—	—	(287)	—	—	(287)
Change in Treasury Stock - Stock Compensation Plans, Net	—	(27,348)	—	—	(9,395)	(36,743)
Restricted Stock and Restricted Stock Units, Net	11	2,552	—	—	(2,563)	—
Stock-Based Compensation Expenses	—	133,849	—	—	—	133,849
Treasury Stock Issued as Compensation	—	27	—	—	2,342	2,369
Balance at December 31, 2017	205,788	5,536,547	(19,297)	10,593,533	(33,298)	16,283,273
Net Income	—	—	—	3,419,040	—	3,419,040
Common Stock Issued Under Stock Plans	8	5,612	—	—	—	5,620
Common Stock Dividends Declared, $0.81 Per Share	—	—	—	(469,443)	—	(469,443)
Other Comprehensive Income	—	—	17,939	—	—	17,939
Change in Treasury Stock - Stock Compensation Plans, Net	—	(35,118)	—	—	(13,336)	(48,454)
	8	(3,891)	—	—	3,883	—

Restricted Stock and Restricted Stock Units, Net						
Stock-Based Compensation Expenses	—	155,337	—	—	—	155,337
Treasury Stock Issued as Compensation	—	307	—	—	569	876
Balance at December 31, 2018	$205,804	$5,658,794	$ (1,358)	$13,543,130	$(42,182)	$19,364,188

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

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

Year Ended December 31	2018	2017	2016
Cash Flows from Operating Activities			
Reconciliation of Net Income (Loss) to Net Cash Provided by Operating Activities:			
Net Income (Loss)	$3,419,040	$2,582,579	$(1,096,686)
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	3,435,408	3,409,387	3,553,417
Impairments	347,021	479,240	620,267
Stock-Based Compensation Expenses	155,337	133,849	128,090
Deferred Income Taxes	894,156	(1,473,872)	(515,206)
(Gains) Losses on Asset Dispositions, Net	(174,562)	99,096	(205,835)
Other, Net	7,066	6,546	61,690
Dry Hole Costs	5,405	4,609	10,657
Mark-to-Market Commodity Derivative Contracts			
Total (Gains) Losses	165,640	(19,828)	99,608
Net Cash Received from (Payments for) Settlements of Commodity Derivative Contracts	(258,906)	7,438	(22,219)
Excess Tax Benefits from Stock-Based Compensation	—	—	(29,357)
Other, Net	3,108	1,204	10,971
Changes in Components of Working Capital and Other Assets and Liabilities			
Accounts Receivable	(368,180)	(392,131)	(232,799)
Inventories	(395,408)	(174,548)	170,694
Accounts Payable	439,347	324,192	(74,048)
Accrued Taxes Payable	(92,461)	(63,937)	92,782
Other Assets	(125,435)	(658,609)	(40,636)
Other Liabilities	10,949	(89,871)	(16,225)
Changes in Components of Working Capital Associated with Investing and Financing Activities	301,083	89,992	(156,102)
Net Cash Provided by Operating Activities	7,768,608	4,265,336	2,359,063
Investing Cash Flows			
Additions to Oil and Gas Properties	(5,839,294)	(3,950,918)	(2,489,756)
Additions to Other Property, Plant and Equipment	(237,181)	(173,324)	(93,039)
Proceeds from Sales of Assets	227,446	226,768	1,119,215
Net Cash Received from Yates Transaction	—	—	54,534
Other Investing Activities	(19,993)	—	—
Changes in Components of Working Capital Associated with Investing Activities	(301,140)	(89,935)	156,102
Net Cash Used in Investing Activities	(6,170,162)	(3,987,409)	(1,252,944)
Financing Cash Flows			
Net Commercial Paper Repayments	—	—	(259,718)
Long-Term Debt Borrowings	—	—	991,097
Long-Term Debt Repayments	(350,000)	(600,000)	(563,829)
Dividends Paid	(438,045)	(386,531)	(372,845)
Excess Tax Benefits from Stock-Based Compensation	—	—	29,357
Treasury Stock Purchased	(63,456)	(63,408)	(82,125)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	20,560	20,840	23,296

Debt Issuance Costs	—	—	(1,602)
Repayment of Capital Lease Obligation	(8,219)	(6,555)	(6,353)
Changes in Components of Working Capital Associated with Financing Activities	57	(57)	—
Net Cash Used in Financing Activities	(839,103)	(1,035,711)	(242,722)
Effect of Exchange Rate Changes on Cash	(37,937)	(7,883)	17,992
Increase (Decrease) in Cash and Cash Equivalents	721,406	(765,667)	881,389
Cash and Cash Equivalents at Beginning of Year	834,228	1,599,895	718,506
Cash and Cash Equivalents at End of Year	$1,555,634	$834,228	$1,599,895

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

EOG RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Principles of Consolidation. The consolidated financial statements of EOG Resources, Inc. (EOG) include the accounts of all domestic and foreign subsidiaries. Investments in unconsolidated affiliates, in which EOG is able to exercise significant influence, are accounted for using the equity method. All intercompany accounts and transactions have been eliminated.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Financial Instruments. EOG's financial instruments consist of cash and cash equivalents, commodity derivative contracts, accounts receivable, accounts payable and current and long-term debt. The carrying values of cash and cash equivalents, commodity derivative contracts, accounts receivable and accounts payable approximate fair value (see Notes 2 and 12).

Cash and Cash Equivalents. EOG records as cash equivalents all highly liquid short-term investments with original maturities of three months or less.

Oil and Gas Operations. EOG accounts for its crude oil and natural gas exploration and production activities under the successful efforts method of accounting.

Oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. Unproved properties with individually significant acquisition costs are reviewed individually for impairment. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether EOG has discovered commercial quantities of proved reserves. If commercial quantities of proved reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether commercial quantities of proved reserves have been discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made (see Note 16). Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Oil and gas properties are grouped in accordance with the provisions of the Extractive Industries - Oil and Gas Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) impairments.

When circumstances indicate that proved oil and gas properties may be impaired, EOG compares expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows, based on EOG's estimate of (and assumptions regarding) future crude oil and natural gas prices, operating costs, development expenditures, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach described in the Fair Value Measurement Topic of the ASC. In certain instances, EOG utilizes accepted offers from third-party purchasers as the basis for determining fair value.

Inventories, consisting primarily of tubular goods, materials for completion operations and well equipment held for use in the exploration for, and development and production of, crude oil and natural gas reserves, are carried at the lower of cost and net realizable value with adjustments made, as appropriate, to recognize any reductions in value.

Revenue Recognition. Effective January 1, 2018, EOG adopted the provisions of Accounting Standards Update (ASU) 2014-09, "Revenue From Contracts With Customers" (ASU 2014-09). ASU 2014-09 and other related ASUs require entities to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. EOG elected to adopt ASU 2014-09 using the modified retrospective approach, which required EOG to recognize in retained earnings the cumulative effect at the date of adoption for all existing contracts with customers which were not substantially complete as of January 1, 2018. There was no impact to retained earnings upon adoption of ASU 2014-09.

EOG presents disaggregated revenues by type of commodity within its Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) and by geographic areas defined as operating segments. See Note 11.

In connection with the adoption of ASU 2014-09, EOG presents natural gas processing fees relating to certain processing and marketing agreements within its United States segment as Gathering and Processing Costs, instead of as a deduction to Revenues within its Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). There was no impact to operating income, net income or cash flows resulting from changes to the presentation of natural gas processing fees. The impacts of the adoption of ASU 2014-09 for the year ended December 31, 2018, were as follows (in thousands):

	As Reported	Amounts Without Adoption of ASU 2014-09	Effect of Change
Operating Revenues and Other			
Crude Oil and Condensate	$9,517,440	$9,517,440	$ —
Natural Gas Liquids	1,127,510	1,121,237	6,273
Natural Gas	1,301,537	1,104,095	197,442
Gathering, Processing and Marketing	5,230,355	5,211,136	19,219
Total Operating Revenues and Other	17,275,399	17,052,465	222,934
Operating Expenses			
Gathering and Processing Costs	436,973	233,258	203,715
Marketing Costs	5,203,243	5,184,024	19,219
Total Operating Expenses	12,806,053	12,583,119	222,934
Operating Income	4,469,346	4,469,346	—

Revenues are recognized for the sale of crude oil and condensate, natural gas liquids (NGLs) and natural gas at the point control of the product is transferred to the customer, typically when production is delivered and title or risk of loss transfers to the customer. Arrangements for such sales are evidenced by signed contracts with prices typically based on stated market indices, with certain adjustments for product quality and geographic location. As EOG typically invoices customers shortly after performance obligations have been fulfilled, contract assets and contract liabilities are not recognized. The balances of accounts receivable from contracts with customers on January 1, 2018 and December 31, 2018, were $1,343 million and $1,460 million, respectively, and are included in Accounts Receivable, Net on the Consolidated Balance Sheets. Losses incurred on receivables from contracts with customers are infrequent and have been immaterial.

Crude Oil and Condensate. EOG sells its crude oil and condensate production at the wellhead or further downstream at a contractually-specified delivery point. Revenue is recognized when control transfers to the customer based on contract terms which reflect prevailing market prices. Any costs incurred prior to the transfer of control, such as gathering and transportation, are recognized as Operating Expenses.

Natural Gas Liquids. EOG delivers certain of its natural gas production to either EOG-owned processing facilities or third-party processing facilities, where extraction of NGLs occurs. For EOG-owned facilities, revenue is recognized after processing upon transfer of NGLs to a customer. For third-party facilities, extracted NGLs are sold to the owner of the processing facility at the tailgate, or EOG takes possession and sells the extracted NGLs at the tailgate or exercises its option to sell further downstream to various customers. Under typical arrangements for third-party facilities, revenue is recognized after processing upon the transfer of control of the NGLs, either at the tailgate of the processing plant or further downstream. EOG recognizes revenues based on contract terms which reflect prevailing market prices, with processing fees recognized as Gathering and Processing Costs.

Natural Gas. EOG sells its natural gas production either at the wellhead or further downstream at a contractually-specified delivery point. In connection with the extraction of NGLs, EOG sells residue gas under separate agreements. Typically, EOG takes possession of the natural gas at the tailgate of the processing facility and sells it at the tailgate or further downstream. In each case, EOG recognizes revenues when control transfers to the customer, based on contract terms which reflect prevailing market prices.

Gathering, Processing and Marketing. Gathering, processing and marketing revenues represent sales of third-party crude oil and condensate, NGLs and natural gas, as well as fees associated with gathering and processing third-party natural gas and revenues from sales of EOG-owned sand. EOG evaluates whether it is the principal or agent under these transactions. As control of the underlying commodity is transferred to EOG prior to the gathering, processing and marketing activities, EOG considers itself the principal of these arrangements. Accordingly, EOG recognizes these transactions on a gross basis. Purchases of third-party commodities are recorded as Marketing Costs, with sales of third-party commodities and fees received for gathering and processing recorded as Gathering, Processing and Marketing revenues.

Other Property, Plant and Equipment. Other property, plant and equipment consists of gathering and processing assets, compressors, buildings and leasehold improvements, crude-by-rail assets, sand mine and sand processing assets, computer hardware and software, vehicles, and furniture and fixtures. Other property, plant and equipment is generally depreciated on a straight-line basis over the estimated useful lives of the property, plant and equipment, which range from 3 years to 45 years.

Capitalized Interest Costs. Interest costs have been capitalized as a part of the historical cost of unproved oil and gas properties. The amount capitalized is an allocation of the interest cost incurred during the reporting period. Capitalized interest is computed only during the exploration and development phases and ceases once production begins. The interest rate used for capitalization purposes is based on the interest rates on EOG's outstanding borrowings. The capitalization of interest is excluded on significant acquisitions of unproved oil and gas properties financed through non-interest-bearing instruments, such as the issuance of shares of Common Stock, or through non-cash property exchanges.

Accounting for Risk Management Activities. Derivative instruments are recorded on the balance sheet as either an asset or liability measured at fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. During the three-year period ended December 31, 2018, EOG elected not to designate any of its financial commodity derivative instruments as accounting hedges and, accordingly, changes in the fair value of these outstanding derivative instruments are recognized as gains or losses in the period of change. The gains or losses are recorded as Gains (Losses) on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). The related cash flow impact of settled contracts is reflected as cash flows from operating activities. EOG employs net presentation of derivative assets and liabilities for financial reporting purposes when such assets and liabilities are with the same counterparty and subject to a master netting arrangement. See Note 12.

Income Taxes. Income taxes are accounted for using the asset and liability approach. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis. EOG assesses the realizability of deferred tax assets and recognizes valuation allowances as appropriate.

In March 2018, the FASB issued ASU 2018-05, "Income Taxes (Topic 740) - Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118" (ASU 2018-05). In December 2017, the United States (U.S.) enacted the Tax Cuts and Jobs Act (TCJA), which made significant changes to U.S. federal income tax law. Shortly after enactment of the TCJA, the United States Securities and Exchange Commission staff issued Staff Accounting Bulletin No. 118 (SAB 118), which provides guidance on accounting for the impact of the TCJA. ASU 2018-05 codified various paragraphs of SAB 118 and was effective upon issuance. Under ASU 2018-05, an entity will use a similar approach as the measurement period provided in the Business Combinations Topic of the ASC. An entity will recognize those matters for which the accounting can be completed. For matters that have not been completed, the entity will either (1) recognize provisional amounts to the extent that they are reasonably able to be estimated and adjust them over time as more information becomes available or (2) for any specific income tax effects of the TCJA for which a reasonable estimate cannot be determined, continue to apply the Income Taxes Topic of the ASC on the basis of the provisions of the tax laws that were in effect immediately before the TCJA was signed into law. EOG has prepared its Consolidated Financial Statements for the year ended December 31, 2018 in accordance with ASU 2018-05. As discussed in EOG's 2017 Annual Report, provisional amounts were recorded for tax accruals as of December 31, 2017 for certain aspects of the TCJA. EOG has updated and finalized the 2017 U.S. federal and state provisional amounts. See Note 6.

Foreign Currency Translation. The United States dollar is the functional currency for all of EOG's consolidated subsidiaries except for its Canadian subsidiaries, for which the functional currency is the Canadian dollar, and its United Kingdom subsidiary (which was sold in the fourth quarter of 2018), for which the functional currency was the British pound. For subsidiaries whose functional currency is deemed to be other than the United States dollar, asset and liability accounts are translated at year-end exchange rates and revenues and expenses are translated at average exchange rates prevailing during the year. Translation adjustments are included in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets. Any gains or losses on transactions or monetary assets or liabilities in currencies other than the functional currency are included in net income in the current period. See Notes 4 and 17.

Net Income (Loss) Per Share. Basic net income (loss) per share is computed on the basis of the weighted-average number of common shares outstanding during the period. Diluted net income (loss) per share is computed based upon the weighted-average number of common shares outstanding during the period plus the assumed issuance of common shares for all potentially dilutive securities. See Note 9.

Stock-Based Compensation. EOG measures the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. See Note 7.

Recently Issued Accounting Standards. In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)" (ASU 2016-02), which significantly changes accounting for leases by requiring that lessees recognize a right-of-use asset and a related lease liability representing the obligation to make lease payments, for certain lease transactions. Additional disclosures about an entity's lease transactions will also be required. ASU 2016-02 defines a lease as "a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration." In January 2018, the FASB issued ASU 2018-01, "Leases (Topic 842) - Land Easement Practical Expedient for Transition to Topic 842" (ASU 2018-01), which permits an entity an optional election to not evaluate under ASU 2016-02 those existing or expired land easements that were not previously accounted for as leases prior to the adoption of ASU 2016-02. Additionally, in July 2018, the FASB issued ASU 2018-11, “Leases (Topic 842) - Targeted Improvements” (ASU 2018-11), which permits an entity (i) to apply the provisions of ASU 2016-02 at the adoption date instead of the earliest period presented in the financial statements, and, as a lessor, (ii) to account for lease and nonlease components as a single component as the nonlease components would otherwise be accounted for under the provisions of ASU 2014-09. ASU 2016-02 and other related ASUs are effective for interim and annual periods beginning after December 31, 2018, and early application is permitted. Based on the provisions of ASU 2018-11 and other related ASUs, lessees and lessors may recognize and measure leases at the beginning of the earliest period presented in the financial statements, defined as the effective date, using a modified retrospective approach, or at the adoption date by recognizing a cumulative-effect adjustment to the opening balance of retained earnings.

EOG is continuing to progress towards the adoption of ASU 2016-02 by implementing its project plan, including a lease accounting software solution. EOG has assessed the scope of its current contractual arrangements, reviewed its existing contracts and is continuing to evaluate certain operational and corporate policies and processes in light of these findings. EOG enters into contracts for drilling services, fracturing services, compression, real estate and other contracts which contain equipment and other assets used in its exploration, development and production activities and corporate functions. Certain of these contracts will require recognition of a right-of-use asset and related lease liability on the Consolidated Balance Sheet, while others will require disclosure within the Notes to the Consolidated Financial Statements.

The impact upon adoption of ASU 2016-02 and other related ASUs is not quantifiable due to the pending determination by EOG of certain accounting policies, including the separation of lease and non-lease components for certain classes of underlying assets, among others. The adoption of ASU 2016-02 and other related ASUs will significantly increase assets and liabilities related to operating leases on the Consolidated Balance Sheets. Non-cancelable operating leases, which will be considered for recognition or disclosure upon adoption of ASU 2016-02 and other related ASUs, totaled $2.0 billion on an undiscounted basis at December 31, 2018, and are included within total minimum commitments in Note 8.

EOG will elect the practical expedient under ASU 2018-11 and apply the provisions of ASU 2016-02 on the adoption date, January 1, 2019. Additionally, EOG will elect the package of practical expedients within ASU 2016-02 that allows an entity to not reassess prior to the effective date (i) whether any expired or existing contracts are or contain leases, (ii) the lease classification for any expired or existing leases, or (iii) initial direct costs for any existing leases, but will not elect the practical expedient of hindsight when determining the lease term of existing contracts at the effective date. EOG also will elect the practical expedient under ASU 2018-01 and not evaluate existing or expired land easements not previously accounted for as leases prior to the effective date.

2. Long-Term Debt

Long-Term Debt at December 31, 2018 and 2017 consisted of the following (in thousands):

	2018	2017
6.875% Senior Notes due 2018	$—	$350,000
5.625% Senior Notes due 2019	900,000	900,000
4.40% Senior Notes due 2020	500,000	500,000
2.45% Senior Notes due 2020	500,000	500,000
4.100% Senior Notes due 2021	750,000	750,000
2.625% Senior Notes due 2023	1,250,000	1,250,000
3.15% Senior Notes due 2025	500,000	500,000
4.15% Senior Notes due 2026	750,000	750,000
6.65% Senior Notes due 2028	140,000	140,000
3.90% Senior Notes due 2035	500,000	500,000
5.10% Senior Notes due 2036	250,000	250,000
Long-Term Debt	6,040,000	6,390,000
Capital Lease Obligation	71,571	32,155
Less: Current Portion of Long-Term Debt	913,093	356,235
Unamortized Debt Discount	24,640	30,564
Debt Issuance Costs	3,669	4,520
Total Long-Term Debt	$5,170,169	$6,030,836

At December 31, 2018, the aggregate annual maturities of long-term debt (excluding capital lease obligations) were $900 million in 2019, $1 billion in 2020, $750 million in 2021, zero in 2022 and $1.25 billion in 2023. At December 31, 2018 and 2017, EOG had no outstanding short-term borrowings under its commercial paper program and no outstanding borrowings under uncommitted credit facilities.

During 2018 and 2017, EOG utilized commercial paper bearing market interest rates, for various corporate financing purposes. The average borrowings outstanding under the commercial paper program were $8 million and $84 million during the years ended December 31, 2018 and 2017, respectively. The weighted average interest rates for commercial paper borrowings were 1.97% and 1.44% for the years 2018 and 2017, respectively.

On October 1, 2018, EOG repaid upon maturity the $350 million aggregate principal amount of its 6.875% Senior Notes due 2018.

On September 15, 2017, EOG repaid upon maturity the $600 million aggregate principal amount of its 5.875% Senior Notes due 2017.

EOG currently has a $2.0 billion senior unsecured Revolving Credit Agreement (Agreement) with domestic and foreign lenders. The Agreement has a scheduled maturity date of July 21, 2020, and includes an option for EOG to extend, on up to two occasions, the term for successive one-year periods subject to certain terms and conditions. Advances under the Agreement will accrue interest based, at EOG's option, on either the London InterBank Offered Rate plus an applicable margin (Eurodollar rate) or the base rate (as defined in the Agreement) plus an applicable margin. The Agreement contains representations, warranties, covenants and events of default that are customary for investment-grade, senior unsecured commercial bank credit agreements, including a financial covenant for the maintenance of a debt-to-total capitalization ratio of no greater than 65%. At December 31, 2018, EOG was in compliance with this financial covenant. At December 31, 2018 and 2017, there were no borrowings or letters of credit outstanding under the Agreement. The Eurodollar rate and applicable base rate, had there been any amounts borrowed under the Agreement at December 31, 2018, would have been 3.50% and 5.50%, respectively.

3. Stockholders' Equity

Common Stock. In September 2001, EOG's Board of Directors (Board) authorized the purchase of an aggregate maximum of 10 million shares of Common Stock that superseded all previous authorizations. At December 31, 2018, 6,386,200 shares remained available for purchase under this authorization. EOG last purchased shares of its Common Stock under this authorization in March 2003. In addition, shares of Common Stock are from time to time withheld by, or returned to, EOG in satisfaction of tax withholding obligations arising upon the exercise of employee stock options or stock-settled stock appreciation rights (SARs), the vesting of restricted stock, restricted stock unit, performance stock or performance unit grants or in payment of the exercise price of employee stock options. Such shares withheld or returned do not count against the Board authorization discussed above. Shares purchased, withheld and returned are held in treasury for, among other purposes, fulfilling any obligations arising under EOG's stock-based compensation plans and any other approved transactions or activities for which such shares of Common Stock may be required.

On August 2, 2018, EOG's Board of Directors increased the quarterly cash dividend on the common stock by 19% from the previous $0.1850 per share to $0.22 per share, effective beginning with the dividend paid on October 31, 2018, to stockholders of record as of October 17, 2018. On February 27, 2018, EOG's Board increased the quarterly cash dividend on the common stock by 10% from the previous $0.1675 per share to $0.1850 per share, effective beginning with the dividend paid on April 30, 2018, to stockholders of record as of April 16, 2018. EOG declared and paid quarterly cash dividends of $0.1675 per share in 2017 and 2016.

On February 15, 2017, the Board approved an amendment to EOG's Restated Certificate of Incorporation to increase the number of EOG's authorized shares of common stock from 640 million to 1,280 million. EOG's stockholders approved the increase at the Annual Meeting of Stockholders on April 27, 2017, and the amendment was filed with the Delaware Secretary of State on April 28, 2017.

On October 4, 2016, EOG issued approximately 25 million shares of EOG common stock in connection with the Yates transaction. See Note 17.

The following summarizes Common Stock activity for each of the years ended December 31, 2016, 2017 and 2018 (in thousands):

	Common Shares		
	Issued	Treasury	Outstanding
Balance at December 31, 2015	550,151	(292)	549,859
Common Stock Issued	25,204	—	25,204
Common Stock Issued Under Stock-Based Compensation Plans	1,500	—	1,500
Treasury Stock Purchased [1]	—	(922)	(922)
Common Stock Issued Under Employee Stock Purchase Plan	95	117	212
Treasury Stock Issued Under Stock-Based Compensation Plans	—	847	847
Balance at December 31, 2016	576,950	(250)	576,700
Common Stock Issued Under Stock-Based Compensation Plans	1,878	—	1,878
Treasury Stock Purchased [1]	—	(686)	(686)
Common Stock Issued Under Employee Stock Purchase Plan	—	180	180
Treasury Stock Issued Under Stock-Based Compensation Plans	—	405	405
Balance at December 31, 2017	578,828	(351)	578,477
Common Stock Issued Under Stock-Based Compensation Plans	1,580	—	1,580
Treasury Stock Purchased [1]	—	(539)	(539)
Common Stock Issued Under Employee Stock Purchase Plan	—	180	180
Treasury Stock Issued Under Stock-Based Compensation Plans	—	325	325
Balance at December 31, 2018	580,408	(385)	580,023

(1) Represents shares that were withheld by or returned to EOG (i) in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or SARs or the vesting of restricted stock, restricted stock unit, performance stock or performance unit grants or (ii) in payment of the exercise price of employee stock options.

Preferred Stock. EOG currently has one authorized series of preferred stock. As of December 31, 2018, there were no shares of preferred stock outstanding.

4. Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) includes certain transactions that have generally been reported in the Consolidated Statements of Stockholders' Equity. The components of Accumulated Other Comprehensive Income (Loss) at December 31, 2018 and 2017 consisted of the following (in thousands):

	Foreign Currency Translation Adjustment	Other	Total
December 31, 2016	$ (19,441)	$431	$(19,010)
Other comprehensive income (loss) before reclassifications	2,799	(3,728)	(929)
Tax effects	—	642	642
Other comprehensive income (loss)	2,799	(3,086)	(287)
December 31, 2017	(16,642)	(2,655)	(19,297)
Other comprehensive income before reclassifications	2,451	1,131	3,582
Amounts reclassified out of other comprehensive income (loss) (1)	14,365	—	14,365
Tax effects	—	(8)	(8)
Other comprehensive income	16,816	1,123	17,939
December 31, 2018	$ 174	$(1,532)	$(1,358)

(1) Reclassified to Net Income (Loss) - Gains (Losses) on Asset Dispositions, Net. See Note 17.

No significant amount was reclassified out of Accumulated Other Comprehensive Income (Loss) during the year ended December 31, 2017.

5. Other Income (Expense), Net

Other income, net for 2018 included interest income ($12 million), a downward adjustment to deferred compensation expense ($6 million) and equity income from investments in ammonia plants in Trinidad ($2 million), partially offset by net foreign currency transaction losses ($(7) million). Other income, net for 2017 included net foreign currency transaction gains ($8 million), interest income ($8 million) and equity income from investments in ammonia plants in Trinidad ($3 million), partially offset by an upward adjustment to deferred compensation expense ($(6) million). Other expense, net for 2016 included net foreign currency transaction losses ($(41) million) and an upward adjustment to deferred compensation expense ($(11) million), partially offset by equity income from investments in ammonia plants in Trinidad ($4 million).

6. Income Taxes

As described in Note 1, EOG finalized the accounting impact of the TCJA on its provisional income tax accruals during 2018 in accordance with ASU 2018-05. Following is a description of each provisional tax accrual and the reason it was adjusted.

During the third quarter of 2018, EOG filed its consolidated 2017 U.S. federal income tax return, along with certain tax elections, and finalized its foreign earnings and profits study. The deemed repatriation tax decreased from the provisional amount of $179 million to $40 million mostly as a result of reducing the repatriation taxable income by net operating losses (NOLs). EOG previously expected to pay the repatriation tax in installments over eight years and preserve NOLs for utilization in future years, as allowed by the TCJA. However, the Internal Revenue Service (IRS) stated in recent guidance that no tax refunds would be issued until the entire repatriation tax liability is satisfied, regardless of the installment election. As a result, EOG did not make the installment election and instead utilized NOLs to reduce the repatriation taxable income. EOG has reviewed the tax consequences of the repatriation tax on its outside basis differences in its investment in non-U.S. subsidiaries and no U.S. federal deferred tax liability is currently required.

EOG recorded a provisional amount in 2017 for its refundable alternative minimum tax (AMT) credits due to the lack of guidance, at that time, on whether any portion of these credits would be sequestered due to a federal budgetary provision. In the first quarter of 2018, the IRS affirmed that any refundable AMT credits resulting from the TCJA would be subject to sequestration. However, in the fourth quarter of 2018, the IRS reversed their decision. Accordingly, EOG eliminated the provisional sequestration accrual and recognized a $42 million tax benefit for the year.

The remeasurement of U.S. deferred tax assets and liabilities resulted in a provisional net tax benefit of $2.2 billion in 2017, which was increased by approximately $52 million in the third quarter of 2018 due to the utilization of the aforementioned NOLs at the 2017 U.S. federal corporate income tax rate of 35% instead of the future tax rate of 21%. This tax benefit, along with the sequestration benefit and other less significant tax reform adjustments, lowered the 2018 full year effective tax rate approximately three percentage points.

The principal components of EOG's total net deferred income tax liabilities at December 31, 2018 and 2017 were as follows (in thousands):

	2018	2017
Deferred Income Tax Assets (Liabilities)		
Foreign Oil and Gas Exploration and Development Costs Deducted for Tax Under Book Depreciation, Depletion and Amortization	$4,359	$(40,851)
Foreign Net Operating Loss	55,175	423,258
Foreign Valuation Allowances	(58,932)	(365,379)
Foreign Other	175	478
Total Net Deferred Income Tax Assets	$777	$17,506
Deferred Income Tax (Assets) Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$4,819,222	$3,894,739
Commodity Hedging Contracts	4,883	(12,008)
Deferred Compensation Plans	(39,086)	(35,832)
Accrued Expenses and Liabilities	(19,097)	12,094
Net Operating Loss - Federal	—	(69,262)
Non-Producing Leasehold Costs	(88,594)	(47,981)
Seismic Costs Capitalized for Tax	(164,932)	(109,423)
Equity Awards	(93,977)	(92,696)
Capitalized Interest	17,821	51,345
Alternative Minimum Tax Credit Carryforward	—	(77,114)
Undistributed Foreign Earnings	22,945	19,684
Other	(45,787)	(15,332)
Total Net Deferred Income Tax Liabilities	$4,413,398	$3,518,214
Total Net Deferred Income Tax Liabilities	$4,412,621	$3,500,708

The components of Income (Loss) Before Income Taxes for the years indicated below were as follows (in thousands):

	2018	2017	2016
United States	$4,084,156	$621,610	$(1,520,573)
Foreign	156,842	39,572	(36,932)
Total	$4,240,998	$661,182	$(1,557,505)

The principal components of EOG's Income Tax Provision (Benefit) for the years indicated below were as follows (in thousands):

	2018	2017	2016
Current:			
Federal	$(303,853)	$33,058	$11,567
State	17,048	(2,502)	(8,369)
Foreign	65,615	35,323	51,189
Total	(221,190)	65,879	54,387
Deferred:			
Federal	862,075	(1,504,288)	(532,979)
State	43,293	26,942	4,876
Foreign	(11,212)	3,474	12,897
Total	894,156	(1,473,872)	(515,206)
Other Non-Current:			
Federal	148,992 (1)	(513,404) (2)	—
Income Tax Provision (Benefit)	$821,958	$(1,921,397)	$(460,819)

(1) Includes change in refundable AMT credits and the reversal of the repatriation tax accrued in 2017. See previous discussion regarding the filing of EOG's 2017 U.S. federal income tax return for details.
(2) Includes refundable AMT credits net of the repatriation tax that was expected to be paid post-2017.

The differences between taxes computed at the U.S. federal statutory tax rate and EOG's effective rate for the years indicated below were as follows:

	2018	2017	2016
Statutory Federal Income Tax Rate	21.00 %	35.00 %	35.00 %
State Income Tax, Net of Federal Benefit	1.12	3.38	0.15
Income Tax Provision Related to Foreign Operations	0.51	(0.30)	(1.23)
Income Tax Provision Related to Trinidad Operations	—	—	(3.71)
Income Tax Provision Related to United Kingdom Operations	—	1.78	—
Income Tax Provision Related to Canadian Operations	—	2.30	—
TCJA	(2.60) (1)	(328.10) (2)	—
Share-Based Compensation (3)	(0.47)	(4.63)	—
Other	(0.18)	(0.03)	(0.62)
Effective Income Tax Rate	19.38 %	(290.60)%	29.59 %

(1) Includes impact of utilizing certain tax NOLs ((1.2)%), the IRS's reversal of its sequestration decision ((1.0)%) and other tax reform impacts ((0.4)%).
(2) Includes impact of the federal rate reduction ((327.8)%), federal repatriation tax ((6.6)%), sequestration (6.4%) and other tax reform impacts ((0.1)%).
(3) Effective January 1, 2017, EOG adopted the provisions of ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting" (ASU 2016-09), which provides that share-based compensation tax benefits and deficiencies are recognized in the income tax provision.

Deferred tax assets are recorded for certain tax benefits, including tax NOLs and tax credit carryforwards, provided that management assesses the utilization of such assets to be "more likely than not." Management assesses the available positive and negative evidence to estimate if sufficient future taxable income will be generated to use the existing deferred tax assets. On the basis of this evaluation, EOG has recorded valuation allowances for the portion of certain foreign and state deferred tax assets that management does not believe are more likely than not to be realized.

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The principal components of EOG's rollforward of valuation allowances for deferred income tax assets for the years indicated below were as follows (in thousands):

	2018	2017	2016
Beginning Balance	$466,421	$383,221	$506,127
Increase (1)	23,062	67,333	37,221
Decrease (2)	(26,219)	(13,687)	(12,667)
Other (3)	(296,122)	29,554	(147,460)
Ending Balance	$167,142	$466,421	$383,221

(1) Increase in valuation allowance related to the generation of tax NOLs and other deferred tax assets.

(2) Decrease in valuation allowance associated with adjustments to certain deferred tax assets and their related allowance.

(3) Represents dispositions, revisions and/or foreign exchange rate variances and the effect of statutory income tax rate changes. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

As of December 31, 2018, EOG had state income tax NOLs being carried forward of approximately $1.8 billion, which, if unused, expire between 2019 and 2037. EOG also has Canadian NOLs of $183 million which can be carried forward 20 years. As described above, these NOLs as well as other less significant future tax benefits, have been evaluated for the likelihood of utilization, and valuation allowances have been established for the portion of these deferred income tax assets that do not meet the “more likely than not” threshold.

The balance of unrecognized tax benefits at December 31, 2018, was $29 million, resulting from the tax treatment of its research and experimental expenditures related to certain innovations in its horizontal drilling and completion projects, of which $12 million may potentially have an earnings impact. EOG records interest and penalties related to unrecognized tax benefits to its income tax provision. Currently $2 million of interest has been recognized in the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). EOG does not anticipate that the amount of the unrecognized tax benefits will change materially during the next twelve months. EOG and its subsidiaries file income tax returns and are subject to tax audits in the U.S. and various state, local and foreign jurisdictions. EOG's earliest open tax years in its principal jurisdictions are as follows: U.S. federal (2016), Canada (2014), Trinidad (2013) and China (2008).

EOG's foreign subsidiaries' undistributed earnings are not considered to be permanently reinvested outside of the U.S. Accordingly, EOG may be required to accrue certain U.S. federal, state, and foreign deferred income taxes on these undistributed earnings as well as on any other outside basis differences related to its investments in these subsidiaries. As of December 31, 2018, EOG has cumulatively recorded $23 million of deferred foreign income taxes for withholdings on its undistributed foreign earnings. Additionally, for tax years beginning in 2018 and later, EOG's foreign earnings may be subject to the U.S. federal "global intangible low-taxed income" (GILTI) inclusion. EOG records any GILTI tax as a period expense.

7. Employee Benefit Plans

Stock-Based Compensation

During 2018, EOG maintained various stock-based compensation plans as discussed below. EOG recognizes compensation expense on grants of stock options, SARs, restricted stock and restricted stock units, performance units and grants made under the EOG Resources, Inc. Employee Stock Purchase Plan (ESPP). Stock-based compensation expense is calculated based upon the grant date estimated fair value of the awards, net of forfeitures, based upon EOG's historical employee turnover rate. Compensation expense is amortized over the shorter of the vesting period or the period from date of grant until the date the employee becomes eligible to retire without company approval.

Stock-based compensation expense is included on the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) based upon the job functions of the employees receiving the grants. Compensation expense related to EOG's stock-based compensation plans for the years ended December 31, 2018, 2017 and 2016 was as follows (in millions):

	2018	2017	2016
Lease and Well	$51	$41	$38
Gathering and Processing Costs	1	1	1
Exploration Costs	25	23	21
General and Administrative	78	69	68
Total	$155	$134	$128

The Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan) provides for grants of stock options, SARs, restricted stock and restricted stock units, performance stock and performance units, and other stock-based awards.

Beginning with the grants made effective September 25, 2017, the Compensation Committee of the Board of Directors of EOG (Committee) approved revised vesting schedules for grants of stock options, SARs, restricted stock and restricted stock units, and performance units. These revised vesting schedules will apply to all future grants as well, until revised, amended or otherwise determined by the Committee.

Grant Type	Previous Vesting Schedule	Revised Vesting Schedule
Stock Options/SARs	Vesting in 25% increments on each of the first four anniversaries of the date of grant	Vesting in increments of 33%, 33% and 34% on each of the first three anniversaries, respectively, of the date of grant
Restricted Stock/Restricted Stock Units	"Cliff" vesting five years from the date of grant	"Cliff" vesting three years from the date of grant
Performance Units	"Cliff" vesting five years from the date of grant (except for the December 2016 grant, which will "cliff" vest approximately three years from the date of grant)	"Cliff" vesting approximately 41 months from the date of grant - specifically, on the February 28th immediately following the Committee’s certifications contemplated by the form of award agreement governing grants of performance units

At December 31, 2018, approximately 13.7 million common shares remained available for grant under the 2008 Plan. EOG's policy is to issue shares related to the 2008 Plan from previously authorized unissued shares or treasury shares to the extent treasury shares are available.

During 2018, 2017 and 2016, EOG issued shares in connection with stock option/SAR exercises, restricted stock and performance stock grants, restricted stock unit and performance unit releases and ESPP purchases. Effective January 1, 2017, with the adoption of ASU 2016-09, EOG began recognizing income tax associated with excess tax benefits and tax deficiencies as discrete benefits and expenses, respectively, in the income tax provision. Net excess tax benefits recognized within the income tax provision were $20 million and $32 million for the twelve months ended December 31, 2018 and 2017, respectively. Prior to the adoption of ASU 2016-09, EOG recognized, as an adjustment to Additional Paid in Capital, federal income tax benefits of $29 million for 2016 related to the exercise of stock options/SARs and the release of restricted stock, restricted stock units, performance stock and performance units.

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Stock Options and Stock-Settled Stock Appreciation Rights and Employee Stock Purchase Plan. Participants in EOG's stock-based compensation plans (including the 2008 Plan) have been or may be granted options to purchase shares of Common Stock. In addition, participants in EOG's stock plans (including the 2008 Plan) have been or may be granted SARs, representing the right to receive shares of Common Stock based on the appreciation in the stock price from the date of grant on the number of SARs granted. Stock options and SARs are granted at a price not less than the market price of the Common Stock on the date of grant. Terms for stock options and SARs granted have generally not exceeded a maximum term of seven years. EOG's ESPP allows eligible employees to semi-annually purchase, through payroll deductions, shares of Common Stock at 85 percent of the fair market value at specified dates. Contributions to the ESPP are limited to 10 percent of the employee's pay (subject to certain ESPP limits) during each of the two six-month offering periods each year.

The fair value of stock option grants and SAR grants is estimated using the Hull-White II binomial option pricing model. The fair value of ESPP grants is estimated using the Black-Scholes-Merton model. Stock-based compensation expense related to stock option, SAR and ESPP grants totaled $60 million, $56 million and $57 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants for the years ended December 31, 2018, 2017 and 2016 were as follows:

	Stock Options/SARs			ESPP		
	2018	2017	2016	2018	2017	2016
Weighted Average Fair Value of Grants	$33.46	$23.95	$25.78	$25.75	$22.20	$19.21
Expected Volatility	28.23 %	28.28 %	31.54 %	24.59 %	27.12 %	36.55 %
Risk-Free Interest Rate	2.68 %	1.52 %	0.78 %	1.89 %	0.88 %	0.44 %
Dividend Yield	0.72 %	0.75 %	0.76 %	0.64 %	0.71 %	0.82 %
Expected Life	5.0 years	5.1 years	5.4 years	0.5 years	0.5 years	0.5 years

Expected volatility is based on an equal weighting of historical volatility and implied volatility from traded options in EOG's Common Stock. The risk-free interest rate is based upon United States Treasury yields in effect at the time of grant. The expected life is based upon historical experience and contractual terms of stock option, SAR and ESPP grants.

The following table sets forth the stock option and SAR transactions for the years ended December 31, 2018, 2017 and 2016 (stock options and SARs in thousands):

	2018		2017		2016	
	Number of Stock Options/SARs	Weighted Average Grant Price	Number of Stock Options/SARs	Weighted Average Grant Price	Number of Stock Options/SARs	Weighted Average Grant Price
Outstanding at January 1	9,103	$ 83.89	9,850	$ 75.53	10,744	$ 67.98
Granted	1,906	126.49	2,274	96.27	1,855	94.82
Exercised [(1)]	(2,493)	72.21	(2,574)	61.12	(2,376)	54.56
Forfeited	(206)	94.43	(447)	93.84	(373)	87.38
Outstanding at December 31	8,310	96.90	9,103	83.89	9,850	75.53
Stock Options/SARs Exercisable at December 31	3,969	85.82	4,510	75.76	5,613	66.48

(1) The total intrinsic value of stock options/SARs exercised during the years 2018, 2017 and 2016 was $118 million, $95 million and $84 million, respectively. The intrinsic value is based upon the difference between the market price of the Common Stock on the date of exercise and the grant price of the stock options/SARs.

At December 31, 2018, there were 8.0 million stock options/SARs vested or expected to vest with a weighted average grant price of $96.43 per share, an intrinsic value of $34.6 million and a weighted average remaining contractual life of 4.4 years.

The following table summarizes certain information for the stock options and SARs outstanding and exercisable at December 31, 2018 (stock options and SARs in thousands):

Stock Options/SARs Outstanding					Stock Options/SARs Exercisable			
Range of Grant Prices	Stock Options/ SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value[(1)]	Stock Options/ SARs	Weighted Average Remaining Life (Years)	Weighted Average Grant Price	Aggregate Intrinsic Value [(1)]
$ 50.00 to $ 82.99	1,528	3	$ 65.46		1,183	2	$ 64.27	
83.00 to 95.99	2,046	4	91.48		1,290	3	89.50	
96.00 to 96.99	1,961	6	96.29		618	5	96.29	
97.00 to 125.99	957	3	102.77		872	3	101.91	
126.00 to 129.99	1,818	7	127.01		6	1	127.00	
	8,310	5	96.90	$ 35,083	3,969	3	85.82	$ 28,993

(1) Based upon the difference between the closing market price of the Common Stock on the last trading day of the year and the grant price of in-the-money stock options and SARs.

At December 31, 2018, unrecognized compensation expense related to non-vested stock option and SAR grants totaled $106 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 1.7 years.

At the 2018 Annual Meeting of Stockholders, EOG stockholders approved an amendment and restatement of the ESPP to (among other changes) increase the number of shares available for grant. At December 31, 2018, approximately 2.5 million shares of Common Stock remained available for grant under the ESPP. The following table summarizes ESPP activity for the years ended December 31, 2018, 2017 and 2016 (in thousands, except number of participants):

	2018	2017	2016
Approximate Number of Participants	1,934	1,870	1,746
Shares Purchased	180	180	212
Aggregate Purchase Price	$14,887	$13,997	$13,787

Restricted Stock and Restricted Stock Units. Employees may be granted restricted (non-vested) stock and/or restricted stock units without cost to them. Upon vesting of restricted stock, shares of Common Stock are released to the employee. Upon vesting, restricted stock units are converted into shares of Common Stock and released to the employee. Stock-based compensation expense related to restricted stock and restricted stock units totaled $81 million, $68 million and $60 million for the years ended December 31, 2018, 2017 and 2016, respectively.

The following table sets forth the restricted stock and restricted stock unit transactions for the years ended December 31, 2018, 2017 and 2016 (shares and units in thousands):

	2018		2017		2016	
	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value
Outstanding at January 1	3,905	$ 88.57	3,962	$ 79.63	4,908	$ 70.35
Granted	812	117.55	1,095	97.34	853	88.01
Released [1]	(740)	78.16	(929)	61.51	(1,465)	53.95
Forfeited	(185)	92.12	(223)	85.45	(334)	77.29
Outstanding at December 31 [2]	3,792	96.64	3,905	88.57	3,962	79.63

(1) The total intrinsic value of restricted stock and restricted stock units released during the years ended December 31, 2018, 2017 and 2016 was $84 million, $91 million and $124 million, respectively. The intrinsic value is based upon the closing price of EOG's common stock on the date restricted stock and restricted stock units are released.

(2) The total intrinsic value of restricted stock and restricted stock units outstanding at December 31, 2018, 2017 and 2016 was $331 million, $421 million and $401 million, respectively.

At December 31, 2018, unrecognized compensation expense related to restricted stock and restricted stock units totaled $172 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 1.9 years.

Performance Units and Performance Stock. EOG has granted performance units and/or performance stock (Performance Awards) to its executive officers annually since 2012. As more fully discussed in the grant agreements, the performance metric applicable to these performance-based grants is EOG's total shareholder return over a three-year performance period relative to the total shareholder return of a designated group of peer companies (Performance Period). Upon the application of the performance multiple at the completion of the Performance Period, a minimum of 0% and a maximum of 200% of the Performance Awards granted could be outstanding. The fair value of the Performance Awards is estimated using a Monte Carlo simulation. Stock-based compensation expense related to the Performance Award grants totaled $14 million, $10 million and $11 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Weighted average fair values and valuation assumptions used to value Performance Awards during the years ended December 31, 2018, 2017 and 2016 were as follows:

	2018	2017	2016
Weighted Average Fair Value of Grants	$136.74	$113.81	$119.10
Expected Volatility	29.92 %	32.19 %	32.48 %
Risk-Free Interest Rate	2.85 %	1.60 %	1.15 %

Expected volatility is based on the term-matched historical volatility over the simulated term, which is calculated as the time between the grant date and the end of the Performance Period. The risk-free interest rate is derived from the Treasury Constant Maturities yield curve on the grant date.

The following table sets forth the Performance Award transactions for the years ended December 31, 2018, 2017 and 2016 (shares and units in thousands):

	2018			2017		2016	
	Number of Units and Shares		Weighted Average Price per Grant Date	Number of Units and Shares	Weighted Average Price per Grant Date	Number of Units and Shares	Weighted Average Price per Grant Date
Outstanding at January 1	502		$ 90.96	545	$ 80.92	405	$ 74.93
Granted	113		125.73	78	96.29	132	100.95
Granted for Performance Multiple (1)	72		101.87	119	84.43	142	56.21
Released (2)	(148)		84.43	(240)	66.69	(134)	56.21
Forfeited	—		—	—	—	—	—
Outstanding at December 31 (3)	539	(4)	101.53	502	90.96	545	80.92

(1) Upon completion of the Performance Period for the Performance Awards granted in 2014, 2013 and 2012, a performance multiple of 200% was applied to each of the grants resulting in additional grants of Performance Awards in February 2018, 2017 and 2016.

(2) The total intrinsic value of Performance Awards released during the years ended December 31, 2018, 2017 and 2016 was $18 million, $24 million and $10 million, respectively.

(3) The total intrinsic value of Performance Awards outstanding at December 31, 2018, 2017 and 2016 was $47 million, $54 million and $55 million, respectively.

(4) Upon the application of the relevant performance multiple at the completion of each of the remaining Performance Periods, a minimum of 144 and a maximum of 934 Performance Awards could be outstanding. The intrinsic value is based upon the closing price of EOG's common stock on the date Performance Awards are released.

At December 31, 2018, unrecognized compensation expense related to Performance Awards totaled $10 million. Such unrecognized expense will be amortized on a straight-line basis over a weighted average period of 1.7 years.

Upon completion of the Performance Period for the Performance Awards granted in 2015, a performance multiple of 200% was applied to the 2015 grants resulting in an additional grant of 71,805 Performance Awards in February 2019.

Pension Plans. EOG has a defined contribution pension plan in place for most of its employees in the United States. EOG's contributions to the pension plan are based on various percentages of compensation and, in some instances, are based upon the amount of the employees' contributions. EOG's total costs recognized for the plan were $43 million, $37 million and $34 million for 2018, 2017 and 2016, respectively.

In addition, EOG's Trinidadian subsidiary maintains a contributory defined benefit pension plan and a matched savings plan. EOG's United Kingdom subsidiary maintained a pension plan which included a non-contributory defined contribution pension plan and a matched defined contribution savings plan. These pension plans are available to most employees of the Trinidadian subsidiary and were available to most employees of the United Kingdom subsidiary. EOG's combined contributions to these plans were $1 million, for each of 2018, 2017 and 2016, respectively. The United Kingdom operations were sold in the fourth quarter of 2018.

For the Trinidadian defined benefit pension plan, the benefit obligation, fair value of plan assets and accrued benefit cost totaled $11 million, $9 million and $0.2 million, respectively, at December 31, 2018, and $10 million, $8 million and $0.2 million, respectively, at December 31, 2017.

Postretirement Health Care. EOG has postretirement medical and dental benefits in place for eligible United States and Trinidad employees and their eligible dependents, the costs of which are not material.

8. Commitments and Contingencies

Letters of Credit and Guarantees. At December 31, 2018 and 2017, respectively, EOG had standby letters of credit and guarantees outstanding totaling $294 million and $174 million, primarily representing guarantees of payment or performance obligations on behalf of subsidiaries. As of February 19, 2019, EOG had received no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2018, total minimum commitments from long-term non-cancelable operating leases, drilling rig commitments, seismic purchase obligations, fracturing services obligations, other purchase obligations and transportation and storage service commitments, based on current transportation and storage rates and the foreign currency exchange rates used to convert Canadian dollars into United States dollars at December 31, 2018, were as follows (in thousands):

	Total Minimum Commitments
2019	$ 2,150,978
2020	1,416,968
2021	996,344
2022	803,240
2023	509,373
2024 and beyond	931,142
	$ 6,808,045

Included in the table above are leases for buildings, facilities and equipment with varying expiration dates through 2042. Rental expenses associated with existing leases amounted to $233 million, $200 million, and $204 million for 2018, 2017 and 2016, respectively.

Contingencies. There are currently various suits and claims pending against EOG that have arisen in the ordinary course of EOG's business, including contract disputes, personal injury and property damage claims and title disputes. While the ultimate outcome and impact on EOG cannot be predicted, management believes that the resolution of these suits and claims will not, individually or in the aggregate, have a material adverse effect on EOG's consolidated financial position, results of operations or cash flow. EOG records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

9. Net Income (Loss) Per Share

The following table sets forth the computation of Net Income (Loss) Per Share for the years ended December 31, 2018, 2017 and 2016 (in thousands, except per share data):

	2018	2017	2016
Numerator for Basic and Diluted Earnings per Share -			
Net Income (Loss)	$3,419,040	$2,582,579	$(1,096,686)
Denominator for Basic Earnings per Share -			
Weighted Average Shares	576,578	574,620	553,384
Potential Dilutive Common Shares -			
Stock Options/SARs	1,137	1,466	—
Restricted Stock/Units and Performance Units/Stock	2,726	2,607	—
Denominator for Diluted Earnings per Share -			
Adjusted Diluted Weighted Average Shares	580,441	578,693	553,384

Net Income (Loss) Per Share			
Basic	$5.93	$4.49	$(1.98)
Diluted	$5.89	$4.46	$(1.98)

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The diluted earnings per share calculation excludes stock options, SARs, restricted stock and units and performance units and stock that were anti-dilutive. Shares underlying the excluded stock options and SARs totaled 0.6 million, 2.6 million and 10.3 million for the years ended December 31, 2018, 2017 and 2016, respectively. For the year ended December 31, 2016, 4.5 million shares of restricted stock and restricted stock units and performance units and performance stock were excluded.

10. Supplemental Cash Flow Information

Net cash paid for interest and income taxes was as follows for the years ended December 31, 2018, 2017 and 2016 (in thousands):

	2018	2017	2016
Interest, Net of Capitalized Interest	$243,279	$275,305	$252,030
Income Taxes, Net of Refunds Received	$75,634	$188,946	$(39,293)

EOG's accrued capital expenditures at December 31, 2018, 2017 and 2016 were $592 million, $475 million and $388 million, respectively.

Non-cash investing activities for the year ended December 31, 2018, included additions of $362 million to EOG's oil and gas properties as a result of property exchanges and an addition of $49 million to EOG's other property, plant and equipment primarily in connection with a capital lease transaction in the Permian Basin.

Non-cash investing activities for the year ended December 31, 2017, included non-cash additions of $282 million to EOG's oil and gas properties as a result of property exchanges.

Non-cash investing activities for the year ended December 31, 2016, included $3,834 million in non-cash additions to EOG's oil and gas properties related to the Yates transaction (see Note 17).

11. Business Segment Information

EOG's operations are all crude oil and natural gas exploration and production related. The Segment Reporting Topic of the ASC establishes standards for reporting information about operating segments in annual financial statements. Operating segments are defined as components of an enterprise about which separate financial information is available and evaluated regularly by the chief operating decision maker, or decision-making group, in deciding how to allocate resources and in assessing performance. EOG's chief operating decision-making process is informal and involves the Chairman of the Board and Chief Executive Officer and other key officers. This group routinely reviews and makes operating decisions related to significant issues associated with each of EOG's major producing areas in the United States, Trinidad, China and the United Kingdom (EOG sold its United Kingdom operations in the fourth quarter of 2018). For segment reporting purposes, the chief operating decision maker considers the major United States producing areas to be one operating segment.

Financial information by reportable segment is presented below as of and for the years ended December 31, 2018, 2017 and 2016 (in thousands):

	United States	Trinidad	Other International (1)	Total
2018				
Crude Oil and Condensate	$9,390,244	$17,059	$110,137	$9,517,440
Natural Gas Liquids	1,127,510	—	—	1,127,510
Natural Gas	970,866	285,053	45,618	1,301,537
Losses on Mark-to-Market Commodity Derivative Contracts	(165,640)	—	—	(165,640)
Gathering, Processing and Marketing	5,227,051	3,304	—	5,230,355
Gains on Asset Dispositions, Net	154,852	4,493	15,217	174,562
Other, Net	89,708	(49)	(24)	89,635
Operating Revenues and Other (2)	16,794,591	309,860	170,948	17,275,399
Depreciation, Depletion and Amortization	3,296,499	91,971	46,938	3,435,408
Operating Income (Loss)	4,334,364	147,240	(12,258)	4,469,346
Interest Income	9,326	1,612	608	11,546
Other Income (Expense)	9,580	2,436	(6,858)	5,158
Net Interest Expense	253,352	—	(8,300)	245,052
Income (Loss) Before Income Taxes	4,099,918	151,288	(10,208)	4,240,998
Income Tax Provision	765,986	54,272	1,700	821,958
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	6,155,874	1,618	37,838	6,195,330
Total Property, Plant and Equipment, Net	27,786,086	210,183	79,250	28,075,519
Total Assets	33,178,733	629,633	126,108	33,934,474

	United States	Trinidad	Other International (1)	Total
2017				
Crude Oil and Condensate	$6,225,711	$13,572	$ 17,113	$6,256,396
Natural Gas Liquids	729,545	—	16	729,561
Natural Gas	615,512	271,101	35,321	921,934
Gains on Mark-to-Market Commodity Derivative Contracts	19,828	—	—	19,828
Gathering, Processing and Marketing	3,298,098	(11)	—	3,298,087
Losses on Asset Dispositions, Net	(98,233)	(8)	(855)	(99,096)
Other, Net	81,610	59	(59)	81,610
Operating Revenues and Other (3)	10,872,071	284,713	51,536	11,208,320
Depreciation, Depletion and Amortization	3,269,196	115,321	24,870	3,409,387
Operating Income (Loss)	933,571	101,010	(108,179)	926,402
Interest Income	3,223	2,201	2,289	7,713
Other Income (Expense)	(9,659)	3,337	7,761	1,439
Net Interest Expense	303,941	—	(29,569)	274,372
Income (Loss) Before Income Taxes	623,194	106,548	(68,560)	661,182
Income Tax Provision (Benefit)	(1,964,343)	38,798	4,148	(1,921,397)
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	4,067,359	145,937	14,932	4,228,228
Total Property, Plant and Equipment, Net	25,125,427	313,357	226,253	25,665,037
Total Assets	28,312,599	974,477	546,002	29,833,078
2016				
Crude Oil and Condensate	$4,265,036	$9,600	$ 42,705	$4,317,341
Natural Gas Liquids	437,238	—	12	437,250
Natural Gas	475,715	234,108	32,329	742,152
Losses on Mark-to-Market Commodity Derivative Contracts	(99,608)	—	—	(99,608)
Gathering, Processing and Marketing	1,967,390	(1,131)	—	1,966,259
Gains (Losses) on Asset Dispositions, Net	196,043	(145)	9,937	205,835
Other, Net	81,386	(8)	25	81,403
Operating Revenues and Other (4)	7,323,200	242,424	85,008	7,650,632
Depreciation, Depletion and Amortization	3,365,390	145,591	42,436	3,553,417
Operating Income (Loss)	(1,192,338)	46,473	(79,416)	(1,225,281)
Interest Income	358	932	1,329	2,619
Other Income (Expense)	(15,703)	2,667	(40,126)	(53,162)
Net Interest Expense	298,125	—	(16,444)	281,681
Income (Loss) Before Income Taxes	(1,505,808)	50,072	(101,769)	(1,557,505)
Income Tax Provision (Benefit)	(516,180)	64,281	(8,920)	(460,819)
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	6,223,228	75,407	30,734	6,329,369
Total Property, Plant and Equipment, Net	25,221,517	274,850	210,711	25,707,078
Total Assets (5)	27,746,851	889,253	663,097	29,299,201

(1) Other International primarily consists of EOG's United Kingdom, China, Canada and Argentina operations. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

(2) EOG had sales activity with two significant purchasers in 2018, one totaling $2.6 billion and the other totaling $2.3 billion of consolidated Operating Revenues and Other in the United States segment.

(3) EOG had sales activity with two significant purchasers in 2017, one totaling $1.5 billion and the other totaling $1.3 billion of consolidated Operating Revenues and Other in the United States segment.

(4) EOG had sales activity with three significant purchasers in 2016, one totaling $1.2 billion, one totaling $1.1 billion and one totaling $1.0 billion of consolidated Operating Revenues and Other in the United States segment.

(5) EOG made a reclassification of $160 million from deferred tax liabilities to deferred tax assets for the year ended December 31, 2016, for the United States segment and in total.

12. Risk Management Activities

Commodity Price Risks. EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, option, swaption, collar and basis swap contracts, as a means to manage this price risk.

During 2018, 2017 and 2016, EOG elected not to designate any of its financial commodity derivative contracts as accounting hedges and, accordingly, accounted for these financial commodity derivative contracts using the mark-to-market accounting method. Under this accounting method, changes in the fair value of outstanding financial instruments are recognized as gains or losses in the period of change and are recorded as Gains (Losses) on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). The related cash flow impact is reflected in Cash Flows from Operating Activities. During 2018, 2017 and 2016, EOG recognized net gains (losses) on the mark-to-market of financial commodity derivative contracts of $(166) million, $20 million and $(100) million, respectively, which included cash received from (payments for) settlements of crude oil and natural gas derivative contracts of $(259) million, $7 million and $(22) million, respectively.

Commodity Derivative Contracts. Prices received by EOG for its crude oil production generally vary from U.S. New York Mercantile Exchange (NYMEX) West Texas Intermediate prices due to adjustments for delivery location (basis) and other factors. EOG has entered into crude oil basis swap contracts in order to fix the differential between pricing in Midland, Texas, and Cushing, Oklahoma (Midland Differential). Presented below is a comprehensive summary of EOG's Midland Differential basis swap contracts for the year ended December 31, 2018. The weighted average price differential expressed in dollars per barrel ($/Bbl) represents the amount of reduction to Cushing, Oklahoma, prices for the notional volumes expressed in barrels per day (Bbld) covered by the basis swap contracts.

Midland Differential Basis Swap Contracts

	Volume (Bbld)	Weighted Average Price Differential ($/Bbl)
2018		
January 1, 2018 through December 31, 2018 (closed)	15,000	$ 1.063
2019		
January 2019 (closed)	20,000	$ 1.075
February 1, 2019 through December 31, 2019	20,000	1.075

EOG has also entered into crude oil basis swap contracts in order to fix the differential between pricing in the U.S. Gulf Coast and Cushing, Oklahoma (Gulf Coast Differential). Presented below is a comprehensive summary of EOG's Gulf Coast Differential basis swap contracts for the year ended December 31, 2018. The weighted average price differential expressed in $/Bbl represents the amount of addition to Cushing, Oklahoma, prices for the notional volumes expressed in Bbld covered by the basis swap contracts.

Gulf Coast Differential Basis Swap Contracts

	Volume (Bbld)	Weighted Average Price

		Differential ($/Bbl)
2018		
January 1, 2018 through September 30, 2018 (closed)	37,000	$ 3.818
October 1, 2018 through December 31, 2018 (closed)	52,000	3.911
2019		
January 2019 (closed)	13,000	$ 5.572
February 1, 2019 through December 31, 2019	13,000	5.572

Presented below is a comprehensive summary of EOG's crude oil price swap contracts for the year ended December 31, 2018, with notional volumes expressed in Bbld and prices expressed in $/Bbl.

Crude Oil Price Swap Contracts

	Volume (Bbld)	Weighted Average Price ($/Bbl)
2018		
January 1, 2018 through November 30, 2018 (closed)	134,000	$ 60.04

On November 20, 2018, EOG entered into crude oil price swap contracts for the period December 1, 2018 through December 31, 2018, with notional volumes of 134,000 Bbld at an average price of $53.75 per Bbl. These contracts offset the crude oil price swap contracts for the same time period with notional volumes of 134,000 Bbld at an average price of $60.04 per Bbl. The net cash EOG received for settling these contracts is $26.1 million. The offsetting contracts are excluded from the above table.

Presented below is a comprehensive summary of EOG's natural gas price swap contracts for the year ended December 31, 2018, with notional volumes expressed in million British thermal units (MMBtu) per day (MMBtud) and prices expressed in dollars per MMBtu ($/MMBtu).

Natural Gas Price Swap Contracts

	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2018		
March 1, 2018 through November 30, 2018 (closed)	35,000	$ 3.00

EOG has sold call options which establish a ceiling price for the sale of notional volumes of natural gas as specified in the call option contracts. The call options require that EOG pay the difference between the call option strike price and either the average or last business day NYMEX Henry Hub natural gas price for the contract month (Henry Hub Index Price) in the event the Henry Hub Index Price is above the call option strike price.

In addition, EOG has purchased put options which establish a floor price for the sale of notional volumes of natural gas as specified in the put option contracts. The put options grant EOG the right to receive the difference between the put option strike price and the Henry Hub Index Price in the event the Henry Hub Index Price is below the put option strike price. Presented below is a comprehensive summary of EOG's natural gas call and put option contracts for the year ended December 31, 2018, with notional volumes expressed in MMBtud and prices expressed in $/MMBtu.

Natural Gas Option Contracts

	Call Options Sold		Put Options Purchased	
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2018				
March 1, 2018 through November 30, 2018 (closed)	120,000	$ 3.38	96,000	$ 2.94

The following table sets forth the amounts and classification of EOG's outstanding derivative financial instruments at December 31, 2018 and 2017, respectively. Certain amounts may be presented on a net basis on the consolidated financial statements when such amounts are with the same counterparty and subject to a master netting arrangement (in millions):

Description	Location on Balance Sheet	Fair Value at December 31, 2018	2017
Asset Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Assets from Price Risk Management Activities	$ 24	$ 8
Noncurrent portion	Other Assets	—	—
Liability Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Liabilities from Price Risk Management Activities (1)	$ —	$ 50
Noncurrent portion	Other Liabilities	—	7

(1) The current portion of Liabilities from Price Risk Management Activities consists of gross liabilities of $55 million, partially offset by gross assets of $5 million, at December 31, 2017.

Credit Risk. Notional contract amounts are used to express the magnitude of a financial derivative. The amounts potentially subject to credit risk, in the event of nonperformance by the counterparties, are equal to the fair value of such contracts (see Note 13). EOG evaluates its exposure to significant counterparties on an ongoing basis, including those arising from physical and financial transactions. In some instances, EOG renegotiates payment terms and/or requires collateral, parent guarantees or letters of credit to minimize credit risk. At December 31, 2018, EOG's net accounts receivable balance related to United States hydrocarbon sales included three receivable balances, each of which accounted for more than 10% of the total balance. The receivables were due from three petroleum refinery companies. The related amounts were collected during early 2019. At December 31, 2017, EOG's net accounts receivable balance related to United States, Canada and United Kingdom hydrocarbon sales included two receivable balances, each of which accounted for more than 10% of the total balance. The receivables were due from two petroleum refinery companies. The related amounts were collected during early 2018. In 2018 and 2017, all natural gas from EOG's Trinidad operations was sold to the National Gas Company of Trinidad and Tobago Limited and its subsidiary. In 2018, all crude oil and condensate from EOG's Trinidad operations was sold to the Petroleum Company of Trinidad and Tobago Limited and its successor, Heritage Petroleum Company Limited. In 2017, all crude oil and condensate from EOG's Trinidad operations was sold to the Petroleum Company of Trinidad and Tobago Limited; and in 2018 and 2017, all natural gas from EOG's China operations was sold to Petrochina Company Limited.

All of EOG's derivative instruments are covered by International Swap Dealers Association Master Agreements (ISDAs) with counterparties. The ISDAs may contain provisions that require EOG, if it is the party in a net liability position, to post collateral when the amount of the net liability exceeds the threshold level specified for EOG's then-current credit ratings. In addition, the ISDAs may also provide that as a result of certain circumstances, including certain events that cause EOG's credit ratings to become materially weaker than its then-current ratings, the counterparty may require all outstanding derivatives under the ISDA to be settled immediately. See Note 13 for the aggregate fair value of all derivative instruments that were in a net liability position at December 31, 2017. EOG had no collateral posted and held no collateral at December 31, 2018 and 2017.

Substantially all of EOG's accounts receivable at December 31, 2018 and 2017 resulted from hydrocarbon sales and/or joint interest billings to third-party companies, including foreign state-owned entities in the oil and gas industry. This concentration of customers and joint interest owners may impact EOG's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. In determining whether or not to require collateral or other credit enhancements from a customer or joint interest owner, EOG typically analyzes the entity's net worth, cash flows, earnings and credit ratings. Receivables are generally not collateralized. During the three-year period ended December 31, 2018, credit losses incurred on receivables by EOG have been immaterial.

13. Fair Value Measurements

Certain of EOG's financial and nonfinancial assets and liabilities are reported at fair value on the Consolidated Balance Sheets. An established fair value hierarchy prioritizes the relative reliability of inputs used in fair value measurements. The hierarchy gives highest priority to Level 1 inputs that represent unadjusted quoted market prices in active markets for identical assets and liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are directly or indirectly observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs and have the lowest priority in the hierarchy. EOG gives consideration to the credit risk of its counterparties, as well as its own credit risk, when measuring financial assets and liabilities at fair value.

The following table provides fair value measurement information within the fair value hierarchy for certain of EOG's financial assets and liabilities carried at fair value on a recurring basis at December 31, 2018 and 2017. Amounts shown in millions.

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
At December 31, 2018				
Financial Assets: [1]				
Crude Oil Basis Swaps	$ —	$ 24	$ —	$ 24
At December 31, 2017				
Financial Assets: [1]				
Natural Gas Swaps	$ —	$ 2	$ —	$ 2
Natural Gas Options/Collars	—	6	—	6
Financial Liabilities: [2]				
Crude Oil Swaps	$ —	$ 38	$ —	$ 38
Crude Oil Basis Swaps	—	19	—	19

(1) $24 million and $8 million is included in "Assets from Price Risk Management Activities" at December 31, 2018 and 2017, respectively, on the Consolidated Balance Sheets.

(2) $50 million is included in "Current Liabilities - Liabilities from Price Risk Management Activities" at December 31, 2017 and $7 million is included in "Other Liabilities" at December 31, 2017, on the Consolidated Balance Sheets.

The estimated fair value of crude oil and natural gas derivative contracts (including options/collars) was based upon forward commodity price curves based on quoted market prices. Commodity derivative contracts were valued by utilizing an independent third-party derivative valuation provider who uses various types of valuation models, as applicable.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of EOG's asset retirement obligations is presented in Note 15.

During 2018, proved oil and gas properties; other property, plant and equipment; and other assets with a carrying amount of $482 million were written down to their fair value of $308 million, resulting in pretax impairment charges of $174 million. Included in the $174 million pretax impairment charges are $104 million of impairments of proved oil and gas properties for which EOG utilized an accepted offer from a third-party purchaser as the basis for determining fair value. In addition, EOG recorded pretax impairment charges in 2018 of $49 million for a commodity price-related write-down of other assets. During 2017, proved oil and gas properties; other property, plant and equipment; and other assets with a carrying amount of $640 million were written down to their fair value of $372 million, resulting in pretax impairment charges of $268 million. Included in the $268 million pretax impairment charges are $217 million of impairments of proved oil and gas properties for which EOG utilized an accepted offer from a third-party purchaser as the basis for determining fair value. In addition, EOG recorded pretax impairment charges in 2017 of $28 million for a commodity price-related write-down of other assets. Significant Level 3 inputs associated with the calculation of discounted cash flows used in the impairment analysis include EOG's estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data.

EOG utilized average prices per acre from comparable market transactions and estimated discounted cash flows as the basis for determining the fair value of unproved and proved properties, respectively, received in non-cash property exchanges. See Note 10.

Fair Value of Debt. At December 31, 2018 and 2017, respectively, EOG had outstanding $6,040 million and $6,390 million aggregate principal amount of senior notes, which had estimated fair values of approximately $6,027 million and $6,602 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, other observable (Level 2) inputs regarding interest rates available to EOG at year-end.

14. Accounting for Certain Long-Lived Assets

EOG reviews its proved oil and gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the asset. The carrying values for assets determined to be impaired were adjusted to estimated fair value using the Income Approach described in the Fair Value Measurement Topic of the ASC. In certain instances, EOG utilizes accepted offers from third-party purchasers as the basis for determining fair value.

During 2018, proved oil and gas properties with a carrying amount of $139 million were written down to their fair value of $18 million, resulting in pretax impairment charges of $121 million. During 2017, proved oil and gas properties with a carrying amount of $370 million were written down to their fair value of $146 million, resulting in pretax impairment charges of $224 million. Impairments in 2018, 2017 and 2016 included domestic legacy natural gas assets. Amortization and impairments of unproved oil and gas property costs, including amortization of capitalized interest, were $173 million, $211 million and $291 million during 2018, 2017 and 2016, respectively.

15. Asset Retirement Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of short-term and long-term legal obligations associated with the retirement of property, plant and equipment for the years ended December 31, 2018 and 2017 (in thousands):

	2018	2017
Carrying Amount at Beginning of Period	$946,848	$912,926
Liabilities Incurred	79,057	54,764
Liabilities Settled [1]	(70,829)	(61,871)
Accretion	36,622	34,708
Revisions	(38,932)	(9,818)
Foreign Currency Translations	1,611	16,139
Carrying Amount at End of Period	$954,377	$946,848
Current Portion	$26,214	$19,259
Noncurrent Portion	$928,163	$927,589

(1) Includes settlements related to asset sales.

The current and noncurrent portions of EOG's asset retirement obligations are included in Current Liabilities - Other and Other Liabilities, respectively, on the Consolidated Balance Sheets.

16. Exploratory Well Costs

EOG's net changes in capitalized exploratory well costs for the years ended December 31, 2018, 2017 and 2016 are presented below (in thousands):

	2018	2017	2016
Balance at January 1	$2,167	$—	$8,955
Additions Pending the Determination of Proved Reserves	10,304	27,487	6,688
Reclassifications to Proved Properties	(7,917)	(20,802)	(5,274)
Costs Charged to Expense [1]	(433)	(4,518)	(10,369)
Balance at December 31	$4,121	$2,167	$—

(1) Includes capitalized exploratory well costs charged to either dry hole costs or impairments.

At December 31, 2018, 2017 and 2016, all exploratory well costs had been capitalized for periods of less than one year.

17. Acquisitions and Divestitures

During 2018, EOG recognized a net gain on asset dispositions of $175 million primarily due to non-cash property exchanges in Texas, New Mexico and Wyoming. Additionally, EOG received proceeds in 2018 of approximately $227 million primarily due to the sale of its United Kingdom operations in the fourth quarter of 2018.

During 2017, EOG recognized a net loss on asset dispositions of $(99) million and received proceeds of approximately $227 million primarily from sales of producing properties, other assets and acreage in Texas and Oklahoma. Additionally, in the fourth quarter of 2017, EOG signed a purchase and sale agreement and an exchange agreement for the sale and exchange, respectively, of primarily producing properties in the Rocky Mountain area. At December 31, 2017, the book value of the assets classified as held for sale and the related asset retirement obligations were $188 million and $41 million, respectively.

During 2017, EOG completed acquisitions of approximately $73 million to acquire producing properties in various areas in the United States.

During 2016, EOG recognized a net gain on asset dispositions of $206 million and received proceeds of approximately $1,119 million primarily from sales of producing properties and acreage in Texas, Louisiana, the Rocky Mountain area and Oklahoma. Additionally, during the third quarter of 2016, EOG completed the sale of all its Argentina assets.

Yates Entities. On October 4, 2016, EOG completed its previously announced mergers and related asset purchase transactions with Yates Petroleum Corporation (YPC), Abo Petroleum Corporation (ABO), MYCO Industries, Inc. (MYCO) and certain affiliated entities (collectively with YPC, ABO and MYCO, the Yates Entities). Pursuant to these transactions, EOG issued to the shareholders of YPC, ABO and MYCO and to certain of the sellers under the related asset purchase transactions an aggregate of approximately 25 million shares of EOG common stock and paid to certain of the sellers under the asset purchase transactions an aggregate of approximately $16 million in cash for total consideration transferred of approximately $2.4 billion. In addition, under the terms of the transactions, EOG assumed and repaid approximately $164 million of debt owed by the Yates Entities, which was offset by approximately $70 million of cash of the Yates Entities.

The assets of the Yates Entities include producing wells in addition to acreage in the Delaware Basin Core, the Powder River Basin, the Permian Basin Northwest Shelf and other Western basins.

In connection with these mergers and related asset purchase transactions, EOG incurred acquisition-related costs in 2016 of approximately $5 million, all of which were expensed and recorded as General and Administrative on the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss).

EOG accounted for the mergers with YPC, ABO and MYCO and the related asset purchase transactions as a business combination under the acquisition method with EOG as the acquirer. Under the acquisition method, the consideration transferred is allocated to the assets acquired and liabilities assumed based on their estimated fair values, with any excess of the consideration transferred over the estimated fair value of the identifiable net assets acquired recorded as goodwill. EOG did not record goodwill in connection with these transactions.

The following table represents the final allocation of the total purchase price of the Yates Entities (in thousands).

Current Assets	
Cash and Cash Equivalents	$70,411
Accounts Receivable, Net	77,073
Inventories	10,955
Other	10,640
Total	169,079
Property, Plant and Equipment	
Oil and Gas Properties (Successful Efforts Method)	3,815,207
Other Property, Plant and Equipment	21,824
Total Property, Plant and Equipment, Net	3,837,031
Other Assets	22,706
Total Assets	$4,028,816
Current Liabilities	
Accounts Payable	$124,145
Accrued Taxes Payable	22,417
Other	743
Total	147,305
Long-Term Debt	163,829
Asset Retirement Obligations	163,144
Off-Market Transportation Contracts	39,720
Other Liabilities	28,645
Deferred Income Taxes	1,072,405
Total Liabilities	$1,615,048
Total Consideration Transferred	$2,413,768

The fair value measurements of Oil and Gas Properties and Asset Retirement Obligations are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of Proved Oil and Gas Properties were measured using the income approach. Significant inputs to the valuation of Proved Oil and Gas Properties included EOG's estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. Significant inputs to the valuation of Unproved Oil and Gas Properties included average prices per acre of comparable market transactions.

EOG RESOURCES, INC.
SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
(In Thousands, Except Per Share Data Unless Otherwise Indicated)
(Unaudited)

Oil and Gas Producing Activities

The following disclosures are made in accordance with Financial Accounting Standards Board Accounting Standards Update No. 2010-03 "Oil and Gas Reserve Estimates and Disclosures" and the United States Securities and Exchange Commission's (SEC) final rule on "Modernization of Oil and Gas Reporting."

Oil and Gas Reserves. Users of this information should be aware that the process of estimating quantities of "proved," "proved developed" and "proved undeveloped" crude oil, natural gas liquids (NGLs) and natural gas reserves is complex, requiring significant subjective decisions in the evaluation of available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors, including, but not limited to, additional development activity; evolving production history; crude oil and condensate, NGL and natural gas prices; and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Although reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. For related discussion, see ITEM 1A, Risk Factors.

Proved reserves represent estimated quantities of crude oil, NGLs 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 under then-existing economic conditions, operating methods and government regulations before 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.

Proved developed reserves are proved reserves expected to be recovered under operating methods being utilized at the time the estimates were made, through wells and equipment in place or if the cost of any required equipment is relatively minor compared to the cost of a new well.

Proved undeveloped reserves (PUDs) are 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. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. PUDs can be recorded in respect of a particular undrilled location only if the location is scheduled, under the then-current drilling and development plan, to be drilled within five years from the date that the PUDs were recorded, unless specific factors (such as those described in interpretative guidance issued by the Staff of the SEC) justify a longer timeframe. Likewise, absent any such specific factors, PUDs associated with a particular undeveloped drilling location shall be removed from the estimates of proved reserves if the location is scheduled, under the then-current drilling and development plan, to be drilled on a date that is beyond five years from the date that the PUDs were recorded. EOG has formulated development plans for all drilling locations associated with its PUDs at December 31, 2018. Under these plans, each PUD location will be drilled within five years from the date it was recorded. Estimates for PUDs are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

In making estimates of PUDs, EOG's technical staff, including engineers and geoscientists, perform detailed technical analysis of each potential drilling location within its inventory of prospects. In making a determination as to which of these locations would penetrate undrilled portions of the formation that can be judged, with reasonable certainty, to be continuous and contain economically producible crude oil and natural gas, studies are conducted using numerous data elements and analysis techniques. EOG's technical staff estimates the hydrocarbons in place, by mapping the entirety of the play in question using seismic techniques, typically employing two-dimensional and three-dimensional data. This analysis is integrated with other static data, including, but not limited to, core analysis, mechanical properties of the formation, thermal maturity indicators, and well logs of existing penetrations. Highly specialized equipment is utilized to prepare rock samples in assessing microstructures which contribute to porosity and permeability.

Analysis of dynamic data is then incorporated to arrive at the estimated fractional recovery of hydrocarbons in place. Data analysis techniques employed include, but are not limited to, well testing analysis, static bottom hole pressure analysis, flowing bottom hole pressure analysis, analysis of historical production trends, pressure transient analysis and rate transient analysis. Application of proprietary rate transient analysis techniques in low permeability rocks allow for quantification of estimates of contribution to production from both fractures and rock matrix.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The impact of optimal completion techniques is a key factor in determining if the PUDs reflected in prospective locations are reasonably certain of being economically producible. EOG's technical staff estimates the recovery improvement that might be achieved when completing horizontal wells with multi-stage fracture stimulation. In the early stages of development of a play, EOG determines the optimal length of the horizontal lateral and multi-stage fracture stimulation using the aforementioned analysis techniques along with pilot drilling programs and gathering of microseismic data.

The process of analyzing static and dynamic data, well completion optimization and the results of early development activities provides the appropriate level of certainty as well as support for the economic producibility of the plays in which PUDs are reflected. EOG has found this approach to be effective based on successful application in analogous reservoirs in low permeability resource plays.

Certain of EOG's Trinidad reserves are held under production sharing contracts where EOG's interest varies with prices and production volumes. Trinidad reserves, as presented on a net basis, assume prices in existence at the time the estimates were made and EOG's estimate of future production volumes. Future fluctuations in prices, production rates or changes in political or regulatory environments could cause EOG's share of future production from Trinidadian reserves to be materially different from that presented.

Estimates of proved reserves at December 31, 2018, 2017 and 2016 were based on studies performed by the engineering staff of EOG. The Engineering and Acquisitions Department is directly responsible for EOG's reserve evaluation process and consists of 16 professionals, all of whom hold, at a minimum, bachelor's degrees in engineering, and four of whom are Registered Professional Engineers. The Vice President, Engineering and Acquisitions is the manager of this department and is the primary technical person responsible for this process. The Vice President, Engineering and Acquisitions holds a Bachelor of Science degree in Petroleum Engineering, has 32 years of experience in reserve evaluations and is a Registered Professional Engineer.

EOG's reserves estimation process is a collaborative effort coordinated by the Engineering and Acquisitions Department in compliance with EOG's internal controls for such process. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, including crude oil, NGL and natural gas prices, production costs, transportation costs, future capital expenditures and EOG's net ownership percentages, are obtained from other departments within EOG. EOG's Internal Audit Department conducts testing with respect to such non-technical inputs. Additionally, EOG engages DeGolyer and MacNaughton (D&M), independent petroleum consultants, to perform independent reserves evaluation of select EOG properties comprising not less than 75% of EOG's estimates of proved reserves. EOG's Board of Directors requires that D&M's and EOG's reserve quantities for the properties evaluated by D&M vary by no more than 5% in the aggregate. Once completed, EOG's year-end reserves are presented to senior management, including the Chairman of the Board and Chief Executive Officer; the Chief Operating Officer; the Executive Vice Presidents, Exploration and Production; and the Executive Vice President and Chief Financial Officer, for approval.

Opinions by D&M for the years ended December 31, 2018, 2017 and 2016 covered producing areas containing 79%, 79% and 83%, respectively, of proved reserves of EOG on a net-equivalent-barrel-of-oil basis. D&M's opinions indicate that the estimates of proved reserves prepared by EOG's Engineering and Acquisitions Department for the properties reviewed by D&M, when compared in total on a net-equivalent-barrel-of-oil basis, do not differ materially from the estimates prepared by D&M. Specifically, such estimates by D&M in the aggregate varied by not more than 5% from those prepared by the Engineering and Acquisitions Department of EOG. All reports by D&M were developed utilizing geological and engineering data provided by EOG. The report of D&M dated January 25, 2019, which contains further discussion of the reserve estimates and evaluations prepared by D&M, as well as the qualifications of D&M's technical person primarily responsible for overseeing such estimates and evaluations, is attached as Exhibit 99.1 to this Annual Report on Form 10-K and incorporated herein by reference.

No major discovery or other favorable or adverse event subsequent to December 31, 2018, is believed to have caused a material change in the estimates of net proved reserves as of that date.

The following tables set forth EOG's net proved reserves at December 31 for each of the four years in the period ended December 31, 2018, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2018, as estimated by the Engineering and Acquisitions Department of EOG:

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NET PROVED RESERVE SUMMARY

	United States	Trinidad	Other International (1)	Total
NET PROVED RESERVES				
Crude Oil (MBbl) (2)				
Net proved reserves at December 31, 2015	1,087,860	1,069	8,667	1,097,596
Revisions of previous estimates	42,040	54	861	42,955
Purchases in place	25,795	—	—	25,795
Extensions, discoveries and other additions	123,441	—	—	123,441
Sales in place	(8,791)	—	—	(8,791)
Production	(101,854)	(284)	(1,273)	(103,411)
Net proved reserves at December 31, 2016	1,168,491	839	8,255	1,177,585
Revisions of previous estimates	57,935	80	(179)	57,836
Purchases in place	1,111	—	—	1,111
Extensions, discoveries and other additions	207,137	301	119	207,557
Sales in place	(8,393)	—	—	(8,393)
Production	(122,210)	(322)	(191)	(122,723)
Net proved reserves at December 31, 2017	1,304,071	898	8,004	1,312,973
Revisions of previous estimates	(13,237)	(183)	44	(13,376)
Purchases in place	2,743	—	—	2,743
Extensions, discoveries and other additions	383,003	—	15	383,018
Sales in place	(768)	—	(6,310)	(7,078)
Production	(144,128)	(298)	(1,542)	(145,968)
Net proved reserves at December 31, 2018	1,531,684	417	211	1,532,312
Natural Gas Liquids (MBbl) (2)				
Net proved reserves at December 31, 2015	382,875	—	—	382,875
Revisions of previous estimates	53,771	—	—	53,771
Purchases in place	1,284	—	—	1,284
Extensions, discoveries and other additions	41,862	—	—	41,862
Sales in place	(33,548)	—	—	(33,548)
Production	(29,878)	—	—	(29,878)
Net proved reserves at December 31, 2016	416,366	—	—	416,366
Revisions of previous estimates	46,843	—	—	46,843
Purchases in place	421	—	—	421
Extensions, discoveries and other additions	75,003	—	—	75,003
Sales in place	(2,887)	—	—	(2,887)
Production	(32,273)	—	—	(32,273)
Net proved reserves at December 31, 2017	503,473	—	—	503,473
Revisions of previous estimates	23,942	—	—	23,942
Purchases in place	2,006	—	—	2,006
Extensions, discoveries and other additions	127,409	—	—	127,409
Sales in place	(41)	—	—	(41)
Production	(42,460)	—	—	(42,460)

Net proved reserves at December 31, 2018	614,329	—	—	614,329

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Trinidad	Other International [(1)]	Total
Natural Gas (Bcf) [(3)]				
Net proved reserves at December 31, 2015	3,489.8	316.6	19.5	3,825.9
Revisions of previous estimates	298.4	29.5	5.2	333.1
Purchases in place	91.5	—	—	91.5
Extensions, discoveries and other additions	202.1	59.9	—	262.0
Sales in place	(752.0)	—	—	(752.0)
Production	(308.6)	(125.1)	(8.9)	(442.6)
Net proved reserves at December 31, 2016	3,021.2	280.9	15.8	3,317.9
Revisions of previous estimates	602.8	(27.4)	8.6	584.0
Purchases in place	4.8	—	—	4.8
Extensions, discoveries and other additions	619.3	174.2	35.9	829.4
Sales in place	(56.4)	—	—	(56.4)
Production	(293.2)	(114.3)	(9.1)	(416.6)
Net proved reserves at December 31, 2017	3,898.5	313.4	51.2	4,263.1
Revisions of previous estimates	(127.2)	20.7	15.0	(91.5)
Purchases in place	41.3	—	—	41.3
Extensions, discoveries and other additions	951.4	—	4.6	956.0
Sales in place	(22.2)	—	—	(22.2)
Production	(351.2)	(97.1)	(11.2)	(459.5)
Net proved reserves at December 31, 2018	4,390.6	237.0	59.6	4,687.2
Oil Equivalents (MBoe) [(2)]				
Net proved reserves at December 31, 2015	2,052,361	53,843	11,913	2,118,117
Revisions of previous estimates	145,542	4,978	1,722	152,242
Purchases in place	42,330	—	—	42,330
Extensions, discoveries and other additions	198,973	9,990	—	208,963
Sales in place	(167,669)	—	—	(167,669)
Production	(183,145)	(21,150)	(2,755)	(207,050)
Net proved reserves at December 31, 2016	2,088,392	47,661	10,880	2,146,933
Revisions of previous estimates	205,262	(4,493)	1,249	202,018
Purchases in place	2,332	—	—	2,332
Extensions, discoveries and other additions	385,354	29,340	6,104	420,798
Sales in place	(20,687)	—	—	(20,687)
Production	(203,351)	(19,366)	(1,707)	(224,424)
Net proved reserves at December 31, 2017	2,457,302	53,142	16,526	2,526,970
Revisions of previous estimates	(10,500)	3,272	2,544	(4,684)
Purchases in place	11,640	—	—	11,640
Extensions, discoveries and other additions	668,972	—	778	669,750
Sales in place	(4,509)	—	(6,310)	(10,819)
Production	(245,127)	(16,478)	(3,406)	(265,011)
Net proved reserves at December 31, 2018	2,877,778	39,936	10,132	2,927,846

(1)

Other International includes EOG's United Kingdom, China, Canada and Argentina operations. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

(2) Thousand barrels or thousand barrels of oil equivalent, as applicable; oil equivalents include crude oil and condensate, NGLs and natural gas. Oil equivalents are determined using a ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet of natural gas.

(3) Billion cubic feet.

During 2018, EOG added 670 million barrels of oil equivalent (MMBoe) of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Permian Basin, the Eagle Ford, the Rocky Mountain area and the Mid-Continent area. Approximately 76% of the 2018 reserve additions were crude oil and condensate and NGLs, and substantially all were in the United States. Sales in place of 11 MMBoe were primarily related to the sale of the United Kingdom operations and the sale or exchange of other producing assets. Revisions of previous estimates of negative 5 MMBoe for 2018 included an upward revision of 35 MMBoe primarily due to increases in the average crude oil and natural gas prices used in the December 31, 2018, reserves estimation as compared to the prices used in the prior year estimate. The primary areas affected were in the Rocky Mountain area, the Eagle Ford and the Permian Basin. Downward revisions other than price of 40 MMBoe resulted primarily from changes in production forecasts and higher production costs. Purchases in place of 12 MMBoe were primarily related to the South Texas Area.

During 2017, EOG added 421 MMBoe of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Permian Basin, the Eagle Ford, the Rocky Mountain area and Trinidad. Approximately 67% of the 2017 reserve additions were crude oil and condensate and NGLs, and 92% were in the United States. Sales in place of 21 MMBoe were primarily related to the sale or exchange of certain producing assets. Revisions of previous estimates of 202 MMBoe for 2017 included an upward revision of 154 MMBoe primarily due to increases in the average crude oil and natural gas prices used in the December 31, 2017, reserves estimation as compared to the prices used in the prior year estimate. The primary plays affected were in the Rocky Mountain area, the Eagle Ford and the Permian Basin. Positive revisions other than price of 48 MMBoe resulted primarily from improved well performance in the Permian Basin and lower production costs. Purchases in place of 2 MMBoe were primarily related to the Permian Basin.

During 2016, EOG added 209 MMBoe of proved reserves from drilling activities and technical evaluation of major proved areas, primarily in the Permian Basin, the Rocky Mountain area and the Eagle Ford. Approximately 79% of the 2016 reserve additions were crude oil and condensate and NGLs, and 95% were in the United States. Sales in place of 168 MMBoe were primarily related to the disposition of certain producing natural gas assets in the Barnett Shale and Haynesville plays and marginal liquids plays in the Permian Basin and Rocky Mountain area. Revisions of previous estimates of 152 MMBoe for 2016 included a downward revision of 101 MMBoe primarily due to decreases in the average crude oil and natural gas prices used in the December 31, 2016, reserves estimation as compared to the prices used in the prior year estimate. The primary plays affected were the Eagle Ford, the Uinta basin in the Rocky Mountain area, the Permian Basin and the Barnett Shale. Positive revisions other than price of 253 MMBoe resulted primarily from lower production costs and improved performance in the Delaware Basin. Purchases in place of 42 MMBoe were primarily related to the Yates transaction.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	Trinidad	Other International (1)	Total
NET PROVED DEVELOPED RESERVES				
Crude Oil (MBbl)				
December 31, 2015	444,070	1,069	63	445,202
December 31, 2016	507,531	839	8,255	516,625
December 31, 2017	605,405	898	7,933	614,236
December 31, 2018	712,218	417	150	712,785
Natural Gas Liquids (MBbl)				
December 31, 2015	205,898	—	—	205,898
December 31, 2016	230,219	—	—	230,219
December 31, 2017	286,872	—	—	286,872
December 31, 2018	341,386	—	—	341,386
Natural Gas (Bcf)				
December 31, 2015	2,211.2	297.6	19.5	2,528.3
December 31, 2016	1,804.4	262.2	15.8	2,082.4
December 31, 2017	2,450.8	299.2	29.3	2,779.3
December 31, 2018	2,699.0	223.9	40.9	2,963.8
Oil Equivalents (MBoe)				
December 31, 2015	1,018,491	50,677	3,309	1,072,477
December 31, 2016	1,038,483	44,543	10,880	1,093,906
December 31, 2017	1,300,758	50,779	12,798	1,364,335
December 31, 2018	1,503,441	37,746	6,950	1,548,137
NET PROVED UNDEVELOPED RESERVES				
Crude Oil (MBbl)				
December 31, 2015	643,790	—	8,604	652,394
December 31, 2016	660,690	—	—	660,690
December 31, 2017	698,666	—	71	698,737
December 31, 2018	819,466	—	61	819,527
Natural Gas Liquids (MBbl)				
December 31, 2015	176,977	—	—	176,977
December 31, 2016	186,147	—	—	186,147
December 31, 2017	216,601	—	—	216,601
December 31, 2018	272,943	—	—	272,943
Natural Gas (Bcf)				
December 31, 2015	1,278.6	19.0	—	1,297.6
December 31, 2016	1,216.8	18.7	—	1,235.5
December 31, 2017	1,447.7	14.2	21.9	1,483.8
December 31, 2018	1,691.6	13.1	18.7	1,723.4
Oil Equivalents (MBoe)				
December 31, 2015	1,033,870	3,166	8,604	1,045,640
December 31, 2016	1,049,909	3,118	—	1,053,027
December 31, 2017	1,156,544	2,363	3,728	1,162,635
December 31, 2018	1,374,337	2,190	3,182	1,379,709

(1) Other International includes EOG's United Kingdom, China, Canada and Argentina operations. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net Proved Undeveloped Reserves. The following table presents the changes in EOG's total proved undeveloped reserves during 2018, 2017 and 2016 (in MBoe):

	2018	2017	2016
Balance at January 1	1,162,635	1,053,027	1,045,640
Extensions and Discoveries	490,725	237,378	138,101
Revisions	(8,244)	33,127	64,413
Acquisition of Reserves	311	—	—
Sale of Reserves	—	(8,253)	(45,917)
Conversion to Proved Developed Reserves	(265,718)	(152,644)	(149,210)
Balance at December 31	1,379,709	1,162,635	1,053,027

For the twelve-month period ended December 31, 2018, total PUDs increased by 217 MMBoe to 1,380 MMBoe. EOG added approximately 31 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs (see discussion of technology employed on pages F-36 and F-37 of this Annual Report on Form 10-K), EOG added 460 MMBoe. The PUD additions were primarily in the Permian Basin, Anadarko Basin, the Eagle Ford and, to a lesser extent, the Rocky Mountain area, and 80% of the additions were crude oil and condensate and NGLs. During 2018, EOG drilled and transferred 266 MMBoe of PUDs to proved developed reserves at a total capital cost of $2,745 million. All PUDs, including drilled but uncompleted wells (DUCs), are scheduled for completion within five years of the original reserve booking.

For the twelve-month period ended December 31, 2017, total PUDs increased by 110 MMBoe to 1,163 MMBoe. EOG added approximately 38 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs, EOG added 199 MMBoe. The PUD additions were primarily in the Permian Basin and, to a lesser extent, the Eagle Ford and the Rocky Mountain area, and 74% of the additions were crude oil and condensate and NGLs. During 2017, EOG drilled and transferred 153 MMBoe of PUDs to proved developed reserves at a total capital cost of $1,440 million. Revisions of PUDs totaled positive 33 MMBoe, primarily due to updated type curves resulting from improved performance of offsetting wells in the Permian Basin, the impact of increases in the average crude oil and natural gas prices used in the December 31, 2017, reserves estimation as compared to the prices used in the prior year estimate, and lower costs. During 2017, EOG sold or exchanged 8 MMBoe of PUDs primarily in the Permian Basin.

For the twelve-month period ended December 31, 2016, total PUDs increased by 7 MMBoe to 1,053 MMBoe. EOG added approximately 21 MMBoe of PUDs through drilling activities where the wells were drilled but significant expenditures remained for completion. Based on the technology employed by EOG to identify and record PUDs, EOG added 117 MMBoe. The PUD additions were primarily in the Permian Basin and, to a lesser extent, the Rocky Mountain area, and 82% of the additions were crude oil and condensate and NGLs. During 2016, EOG drilled and transferred 149 MMBoe of PUDs to proved developed reserves at a total capital cost of $1,230 million. Revisions of PUDs totaled positive 64 MMBoe, primarily due to improved well performance, primarily in the Delaware Basin, and lower production costs, partially offset by the impact of decreases in the average crude oil and natural gas prices used in the December 31, 2016, reserves estimation as compared to the prices used in the prior year estimate. During 2016, EOG sold 46 MMBoe of PUDs primarily in the Haynesville play.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Capitalized Costs Relating to Oil and Gas Producing Activities. The following table sets forth the capitalized costs relating to EOG's crude oil and natural gas producing activities at December 31, 2018 and 2017:

	2018	2017
Proved properties	$53,624,809	$48,845,672
Unproved properties	3,705,207	3,710,069
Total	57,330,016	52,555,741
Accumulated depreciation, depletion and amortization	(31,674,085)	(29,191,247)
Net capitalized costs	$25,655,931	$23,364,494

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities. The acquisition, exploration and development costs disclosed in the following tables are in accordance with definitions in the Extractive Industries - Oil and Gas Topic of the Accounting Standards Codification (ASC).

Acquisition costs include costs incurred to purchase, lease or otherwise acquire property.

Exploration costs include additions to exploratory wells, including those in progress, and exploration expenses.

Development costs include additions to production facilities and equipment and additions to development wells, including those in progress.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth costs incurred related to EOG's oil and gas activities for the years ended December 31, 2018, 2017 and 2016:

	United States	Trinidad	Other International [(1)]	Total
2018				
Acquisition Costs of Properties				
Unproved [(2)]	$486,081	$1,258	$ —	$487,339
Proved [(3)]	123,684	—	—	123,684
Subtotal	609,765	1,258	—	611,023
Exploration Costs	157,222	22,511	13,895	193,628
Development Costs [(4)]	5,605,264	(12,863)	22,628	5,615,029
Total	$6,372,251	$10,906	$ 36,523	$6,419,680
2017				
Acquisition Costs of Properties				
Unproved [(5)]	$424,118	$2,422	$ —	$426,540
Proved [(6)]	72,584	—	—	72,584
Subtotal	496,702	2,422	—	499,124
Exploration Costs	144,499	62,547	16,553	223,599
Development Costs [(7)]	3,590,899	109,491	16,297	3,716,687
Total	$4,232,100	$174,460	$ 32,850	$4,439,410
2016				
Acquisition Costs of Properties				
Unproved [(8)]	$3,216,598	$—	$ 36	$3,216,634
Proved [(9)]	749,023	—	—	749,023
Subtotal	3,965,621	—	36	3,965,657
Exploration Costs	156,295	2,695	6,761	165,751
Development Costs [(10)]	2,252,713	72,147	(10,984)	2,313,876
Total	$6,374,629	$74,842	$ (4,187)	$6,445,284

(1) Other International primarily consists of EOG's United Kingdom, China, Canada and Argentina operations. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

(2) Includes non-cash unproved leasehold acquisition costs of $291 million related to property exchanges.

(3) Includes non-cash proved property acquisition costs of $71 million related to property exchanges.

(4) Includes Asset Retirement Costs of $90 million, $(12) million and $(8) million for the United States, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

(5) Includes non-cash unproved leasehold acquisition costs of $256 million related to property exchanges.

(6) Includes non-cash proved property acquisition costs of $26 million related to property exchanges.

(7) Includes Asset Retirement Costs of $50 million, $2 million and $4 million for the United States, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

(8) Includes non-cash unproved leasehold acquisition costs of $3,102 million related to the Yates transaction.

(9) Includes non-cash proved property acquisition costs of $732 million related to the Yates transaction.

(10) Includes Asset Retirement Costs of $25 million, $(3) million and $(42) million for the United States, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

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EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Results of Operations for Oil and Gas Producing Activities [1]. The following table sets forth results of operations for oil and gas producing activities for the years ended December 31, 2018, 2017 and 2016:

	United States	Trinidad	Other International [2]	Total
2018				
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$11,488,620	$302,112	$155,755	$11,946,487
Other	89,708	(49)	(24)	89,635
Total	11,578,328	302,063	155,731	12,036,122
Exploration Costs	121,572	21,402	6,025	148,999
Dry Hole Costs	4,983	—	422	5,405
Transportation Costs	742,792	3,236	848	746,876
Gathering and Processing Costs [3]	404,471	—	32,502	436,973
Production Costs	1,924,504	33,506	70,073	2,028,083
Impairments	344,595	—	2,426	347,021
Depreciation, Depletion and Amortization	3,181,801	91,788	46,687	3,320,276
Income Before Income Taxes	4,853,610	152,131	(3,252)	5,002,489
Income Tax Provision	1,086,077	12,170	1,898	1,100,145
Results of Operations	$3,767,533	$139,961	$(5,150)	$3,902,344
2017				
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$7,570,768	$284,673	$52,450	$7,907,891
Other	81,610	59	(59)	81,610
Total	7,652,378	284,732	52,391	7,989,501
Exploration Costs	113,334	26,245	5,763	145,342
Dry Hole Costs	91	—	4,518	4,609
Transportation Costs	737,403	1,885	1,064	740,352
Production Costs	1,446,333	27,839	88,038	1,562,210
Impairments	477,223	—	2,017	479,240
Depreciation, Depletion and Amortization	3,157,056	115,174	24,536	3,296,766
Income (Loss) Before Income Taxes	1,720,938	113,589	(73,545)	1,760,982
Income Tax Provision (Benefit)	625,562	24,882	(1,342)	649,102
Results of Operations	$1,095,376	$88,707	$(72,203)	$1,111,880
2016				
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$5,177,989	$243,708	$75,046	$5,496,743
Other	81,386	(8)	25	81,403
Total	5,259,375	243,700	75,071	5,578,146
Exploration Costs	115,990	2,647	6,316	124,953
Dry Hole Costs	10,529	—	128	10,657
Transportation Costs	753,791	1,181	9,134	764,106
Production Costs	1,163,827	27,113	63,073	1,254,013
Impairments	611,297	7,773	1,197	620,267
Depreciation, Depletion and Amortization	3,249,792	145,440	42,052	3,437,284
Income (Loss) Before Income Taxes	(645,851)	59,546	(46,829)	(633,134)

Income Tax Provision (Benefit)	(230,377)	5,526	(1,562)	(226,413)
Results of Operations	$(415,474)	$54,020	$(45,267)	$(406,721)

(1) Excludes gains or losses on the mark-to-market of financial commodity derivative contracts, gains or losses on sales of reserves and related assets, interest charges and general corporate expenses for each of the three years in the period ended December 31, 2018.

(2) Other International primarily consists of EOG's United Kingdom, China, Canada and Argentina operations. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

(3) Effective January 1, 2018, EOG adopted the provisions of Accounting Standards Update (ASU) 2014-09, "Revenue From Contracts With Customers" (ASU 2014-09). In connection with the adoption of ASU 2014-09, EOG presents natural gas processing fees relating to certain processing and marketing agreements within its United States segment as Gathering and Processing Costs instead of as a deduction to Natural Gas Revenues. There was no impact to operating income or net income resulting from changes to the presentation of natural gas processing fees (see Note 1 to Consolidated Financial Statements).

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SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth production costs per barrel of oil equivalent, excluding severance/production and ad valorem taxes, for the years ended December 31, 2018, 2017 and 2016:

	United States	Trinidad	Other International (1)	Composite
Year Ended December 31, 2018	$ 4.84	$ 1.67	$ 20.19	$ 4.84
Year Ended December 31, 2017	$ 4.58	$ 1.39	$ 50.86	$ 4.66
Year Ended December 31, 2016	$ 4.58	$ 1.23	$ 22.43	$ 4.48

(1) Other International primarily consists of EOG's United Kingdom, China, Canada and Argentina operations. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves. The following information has been developed utilizing procedures prescribed by the Extractive Industries - Oil and Gas Topic of the ASC and based on crude oil, NGL and natural gas reserves and production volumes estimated by the Engineering and Acquisitions Department of EOG. The estimates were based on a 12-month average for commodity prices for the years 2018, 2017 and 2016. The following information may be useful for certain comparative purposes, but should not be solely relied upon in evaluating EOG or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of EOG.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil, NGL and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable and possible reserves as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth the standardized measure of discounted future net cash flows from projected production of EOG's oil and gas reserves for the years ended December 31, 2018, 2017 and 2016:

	United States	Trinidad	Other International (1)	Total
2018				
Future cash inflows (2)	$133,066,375	$749,695	$303,620	$134,119,690
Future production costs	(42,351,174)	(204,444)	(99,024)	(42,654,642)
Future development costs	(16,577,794)	(78,199)	(11,900)	(16,667,893)
Future income taxes	(14,756,011)	(174,382)	(31,748)	(14,962,141)
Future net cash flows	59,381,396	292,670	160,948	59,835,014
Discount to present value at 10% annual rate	(27,348,744)	(26,832)	(33,483)	(27,409,059)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$32,032,652	$265,838	$127,465	$32,425,955
2017				
Future cash inflows (3)	$83,652,363	$904,141	$664,560	$85,221,064
Future production costs	(32,018,812)	(239,213)	(311,383)	(32,569,408)
Future development costs	(13,395,873)	(84,379)	(58,543)	(13,538,795)
Future income taxes	(5,948,453)	(195,855)	(16,233)	(6,160,541)
Future net cash flows	32,289,225	384,694	278,401	32,952,320
Discount to present value at 10% annual rate	(14,532,290)	(52,267)	(40,103)	(14,624,660)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$17,756,935	$332,427	$238,298	$18,327,660
2016				
Future cash inflows (4)	$57,913,314	$524,523	$402,587	$58,840,424
Future production costs	(27,625,833)	(165,757)	(227,293)	(28,018,883)
Future development costs	(12,602,699)	(103,631)	(35,602)	(12,741,932)
Future income taxes	(3,151,319)	(60,001)	—	(3,211,320)
Future net cash flows	14,533,463	195,134	139,692	14,868,289
Discount to present value at 10% annual rate	(6,039,736)	(9,384)	(7,012)	(6,056,132)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$8,493,727	$185,750	$132,680	$8,812,157

(1) Other International includes EOG's United Kingdom, China, Canada and Argentina operations. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

(2) Estimated crude oil prices used to calculate 2018 future cash inflows for the United States, Trinidad and Other International were $68.54, $55.66 and $61.66, respectively. Estimated NGL price used to calculate 2018 future cash inflows for the United States was $27.83. Estimated natural gas prices used to calculate 2018 future cash inflows for the United States, Trinidad and Other International were $2.50, $3.06 and $4.88, respectively.

(3) Estimated crude oil prices used to calculate 2017 future cash inflows for the United States, Trinidad and Other International were $49.21, $41.87 and $50.06, respectively. Estimated NGL price used to calculate 2017 future cash inflows for the United States was $23.51. Estimated natural gas prices used to calculate 2017 future cash inflows for the United States, Trinidad and Other International were $1.96, $2.76 and $5.16, respectively.

(4) Estimated crude oil prices used to calculate 2016 future cash inflows for the United States, Trinidad and Other International were $40.70, $34.79 and $39.55, respectively. Estimated NGL price used to calculate 2016 future

cash inflows for the United States was $14.69. Estimated natural gas prices used to calculate 2016 future cash inflows for the United States, Trinidad and Other International were $1.40, $1.76 and $4.84, respectively.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for each of the three years in the period ended December 31, 2018:

	United States	Trinidad	Other International [(1)]	Total
December 31, 2015	$8,965,467	$381,124	$274,805	$9,621,396
Sales and transfers of oil and gas produced, net of production costs	(3,260,372)	(215,414)	(2,839)	(3,478,625)
Net changes in prices and production costs	(3,352,802)	(182,876)	(143,924)	(3,679,602)
Extensions, discoveries, additions and improved recovery, net of related costs	865,066	42,201	—	907,267
Development costs incurred	1,207,000	3,900	19,100	1,230,000
Revisions of estimated development cost	2,092,769	22,596	6,343	2,121,708
Revisions of previous quantity estimates	1,013,753	36,648	2,619	1,053,020
Accretion of discount	970,388	56,566	27,481	1,054,435
Net change in income taxes	738,416	129,622	—	868,038
Purchases of reserves in place	377,872	—	—	377,872
Sales of reserves in place	(375,793)	—	—	(375,793)
Changes in timing and other	(748,037)	(88,617)	(50,905)	(887,559)
December 31, 2016	8,493,727	185,750	132,680	8,812,157
Sales and transfers of oil and gas produced, net of production costs	(5,387,031)	(254,948)	36,649	(5,605,330)
Net changes in prices and production costs	6,606,908	436,969	77,668	7,121,545
Extensions, discoveries, additions and improved recovery, net of related costs	3,644,041	270,255	43,952	3,958,248
Development costs incurred	1,435,600	4,700	—	1,440,300
Revisions of estimated development cost	(114,464)	9,683	(20,096)	(124,877)
Revisions of previous quantity estimates	2,460,498	(58,373)	36,146	2,438,271
Accretion of discount	849,373	24,066	13,268	886,707
Net change in income taxes	(1,918,989)	(114,575)	(10,099)	(2,043,663)
Purchases of reserves in place	30,362	—	—	30,362
Sales of reserves in place	(76,527)	—	—	(76,527)
Changes in timing and other	1,733,437	(171,100)	(71,870)	1,490,467
December 31, 2017	17,756,935	332,427	238,298	18,327,660
Sales and transfers of oil and gas produced, net of production costs	(8,416,853)	(265,370)	(52,399)	(8,734,622)
Net changes in prices and production costs	12,750,466	84,353	21,610	12,856,429
Extensions, discoveries, additions and improved recovery, net of related costs	8,418,666	—	12,287	8,430,953
Development costs incurred	2,732,560	—	12,600	2,745,160
Revisions of estimated development cost	(410,741)	4,030	(3,814)	(410,525)
Revisions of previous quantity estimates	(173,084)	39,608	31,750	(101,726)
Accretion of discount	1,967,592	50,191	24,839	2,042,622
Net change in income taxes	(4,965,373)	3,844	(11,529)	(4,973,058)

Purchases of reserves in place	116,887	—	—	116,887
Sales of reserves in place	(35,874)	—	(82,058)	(117,932)
Changes in timing and other	2,291,471	16,755	(64,119)	2,244,107
December 31, 2018	$32,032,652	$265,838	$127,465	$32,425,955

(1) Other International includes EOG's United Kingdom, China, Canada and Argentina operations. The United Kingdom operations were sold in the fourth quarter of 2018. The Argentina operations were sold in the third quarter of 2016.

EOG RESOURCES, INC.

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

Unaudited Quarterly Financial Information
(In Thousands, Except Per Share Data)

Quarter Ended	Mar 31	Jun 30	Sep 30	Dec 31
2018				
Operating Revenues and Other	$3,681,162	$4,238,077	$4,781,624	$4,574,536
Operating Income	$874,588	$964,931	$1,506,687	$1,123,140
Income Before Income Taxes	$813,359	$892,936	$1,446,363	$1,088,340
Income Tax Provision	174,770	196,205	255,411	195,572
Net Income	$638,589	$696,731	$1,190,952	$892,768
Net Income Per Share [1]				
Basic	$1.11	$1.21	$2.06	$1.55
Diluted	$1.10	$1.20	$2.05	$1.54
Average Number of Common Shares				
Basic	575,775	576,135	577,254	577,035
Diluted	579,726	580,375	581,559	580,288
2017				
Operating Revenues and Other	$2,610,565	$2,612,472	$2,644,844	$3,340,439
Operating Income	$107,746	$127,908	$214,836	$475,912
Income Before Income Taxes	$39,382	$62,467	$145,980	$413,353
Income Tax Provision (Benefit) [2]	10,865	39,414	45,439	(2,017,115)
Net Income	$28,517	$23,053	$100,541	$2,430,468
Net Income Per Share [1]				
Basic	$0.05	$		