2017

Return-Focused

EOG Resources

William R. Thomas

Chairman of the Board and Chief Executive Officer

EOG is a rate-of-return incentivized company and has been since its founding. Our return-focused culture prompted a rigorous upgrade to our investment return standard at the bottom of the commodity price cycle in 2016: in order to be considered for capital dollars, new wells are required to earn a minimum 30 percent rate of return[A] at $40 oil and $2.50 natural gas.

"Going forward, our vision is to be the E&P company earning ROCE that is not only the best among our peers but also competitive with the best companies outside our industry."

This "premium well" capital allocation standard has permanently changed the game. We did not relax the standard in the face of improving prices in 2017. All seven of EOG's operating teams across every major North American basin and our international teams know that to receive funding, investments need to exceed the premium return hurdle rate.

We are proud to report that our operational teams delivered in 2017. Our drilling program earned an average rate of return[A] of 63% calculated on the premium $40 oil price deck and 92% using 2017 realized prices.

More importantly, these rates of return are reflected in our bottom-line financial performance and in our operational performance. In 2017, we realized significant improvement in our net income, cash flow and return on capital employed (ROCE) and increased U.S. oil production 20 percent while reducing debt, paying our dividend and generating free cash flow. These results are particularly remarkable given that oil averaged a modest $50 a barrel last year - a testament to the capital efficiency of our premium drilling inventory. An average premium well's first year gross oil production is twice as much for about half the finding cost of a non-premium well, which translates to a roughly fivefold increase in returns.[B]

What is equally important is how we consistently replace our inventory. We continue to improve both the size and quality by organically adding better locations substantially faster than our drilling pace. We added 2,000 net premium locations in 2017, which is almost four times the number of net wells completed.

New drilling inventory was sourced from both existing and emerging plays - we added the First Bone Spring Sand target in the Delaware Basin and introduced the Woodford Oil Window in the Eastern Anadarko Basin.

Our premium inventory now totals a massive 8,000 net locations and 7.3 billion barrels of oil equivalent[C] in geologic sweet spots across six areas, the Delaware Basin, Eagle Ford, Bakken, Powder River Basin, DJ Basin and Anadarko Basin. The diversity of our horizontal oil assets is unmatched in the industry. This unique competitive advantage provides the scale and flexibility critical to sustain both healthy growth and high returns.

Looking ahead to 2018, we expect to grow oil 18 percent, earn double digit ROCE, pay the dividend and generate free cash flow. Moreover, we can deliver this first-class performance at oil prices as low as $50. That is the power of premium.

EOG has a history of earning peer-leading ROCE, averaging 13 percent over the past 20 years.[D] Our return-focus and diverse portfolio of assets, supported by a bottom-up, flat, decentralized organization, continues to drive differentiated ROCE performance in the Exploration and Production (E&P) space.

"Our return-focus and diverse portfolio of assets, supported by a bottom-up, flat, decentralized organization continues to drive differentiated ROCE performance in the E&P space."

Going forward, our vision is to be the E&P company earning ROCE that is not only the best among our peers, but also competitive with the best companies outside our industry. How do we do that? Capital discipline and a premium capital allocation standard that will sustain ROCE throughout the commodity price cycle. We believe this is the best way to create sustainable long-term shareholder value.

EOG is a high-return organic growth company poised to be a leader in both returns and growth for decades to come.

William R. Thomas

William R. Thomas
Chairman and Chief Executive Officer

February 27, 2018

Footnotes

(A) Direct after-tax rate of return definition on page 114.

(B) Calculated using estimated reserves, production volumes and capital expenditures associated with 2016 completed wells and futures strip prices in February 2017.

(C) Net estimated potential reserves, not proved reserves.

(D) Refer to reconciliation schedules on pages 115 - 118. ROCE in 2013 and prior years calculated using reported net income (GAAP) and 2014 – 2017 using adjusted net income (Non-GAAP).

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2017

or

☐ **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 ☒ No ☐

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 ☐ No ☒

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes ☒ No ☐

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

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company)
Smaller reporting company ☐ Emerging growth company ☐

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

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

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, 2017: $52,112 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, 578,636,343 shares outstanding as of February 16, 2018.

Documents incorporated by reference. Portions of the Definitive Proxy Statement for the registrant's 2018 Annual Meeting of Stockholders, to be filed within 120 days after December 31, 2017, 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 United Kingdom (U.K.), 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 are made available, free of charge, through EOG's website, as soon as reasonably practicable after such reports have been filed with 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, 2017, EOG's total estimated net proved reserves were 2,527 million barrels of oil equivalent (MMBoe), of which 1,313 million barrels (MMBbl) were crude oil and condensate reserves, 503 MMBbl were natural gas liquids (NGLs) reserves and 4,263 billion cubic feet (Bcf), or 711 MMBoe, were natural gas reserves (see "Supplemental Information to Consolidated Financial Statements"). At such date, approximately 97% of EOG's net proved reserves, on a crude oil equivalent basis, were located in the United States, 2% 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, 2017, EOG employed approximately 2,664 persons, including foreign national employees.

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 drill bits, completion technologies for horizontal drilling and formation evaluation. These advanced technologies are used, as appropriate, throughout EOG to reduce the risks 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 prudent and safe 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.

Business Segments

EOG's operations are all crude oil and natural gas exploration and production related. For financial information about our reportable segments (including financial information by segment geographic area), see Note 11 to Consolidated Financial Statements. For information regarding the risks associated with EOG's domestic and foreign operations, see ITEM 1A, Risk Factors.

Exploration and Production

United States Operations

EOG's operations are focused 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, 2017, on a crude oil equivalent basis, 54% of EOG's net proved reserves in the United States were crude oil and condensate, 20% 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.

The following is a summary of significant developments during 2017 and certain 2018 plans for EOG's United States operations.

	2017					2018
Area of Operation	Crude Oil & Condensate Volumes (MBbld)	Natural Gas Liquids Volumes (MBbld)	Natural Gas Volumes (MMcfd)	Total Net Acres (1)	Net Well Completions	Expected Net Well Completions
Eagle Ford	157	26	151	582,000	217	260
Austin Chalk	14	5	29	— (2)	28	25
Permian Basin	91	24	235	630,000	172	240
Rocky Mountain Area	66	14	195	1,200,000	93	100
Upper Gulf Coast	1	1	7	354,000	4	1
Mid-Continent	2	1	12	130,000	5	35
Fort Worth Basin	3	16	94	169,000	—	—
South Texas	1	1	18	238,000	2	12
Marcellus Shale	—	—	24	177,000	4	12

(1) Total net acres excludes approximately 1.2 million net acres related to other areas.
(2) 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 2.0 billion barrels of crude oil and condensate. With approximately 520,000 of its 582,000 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 420 MMBbl of crude oil and condensate. In 2017, EOG completed 217 net Eagle Ford wells and continued to test the Austin Chalk play concept with the completion of 28 net Austin Chalk wells. EOG is still evaluating the extent of prospectivity of the Austin Chalk, which overlays the Eagle Ford. EOG also expanded its enhanced oil recovery (EOR) gas injection program in 2017, adding 56 wells to the program. Based on encouraging results, EOG plans to include an additional 90 wells in 2018 bringing the total number of wells in its EOR program to 178 by year end. In 2018, EOG expects to complete approximately 260 net Eagle Ford wells and 25 net Austin Chalk wells while continuing to improve well productivity and operational efficiencies. The combination of self-sourced sand, dedicated completions crews and other services along with continuous well optimization programs have made this play a centerpiece of EOG's portfolio.

In the Permian Basin, EOG completed 172 net wells during 2017, primarily in the Delaware Basin Wolfcamp Shale, Second 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. In the Delaware Basin Wolfcamp Shale play, where it has approximately 346,000 net acres, EOG followed a development plan with well spacing as close as 500 feet in the crude oil portion and 880 feet in the combo portion. The success of the 2017 Wolfcamp program was due to precision targeting, high-density stimulations, cost reductions, and lateral length extensions. The average lateral length of completed wells in the play increased from approximately 5,200 feet in 2016 to approximately 6,100 feet in 2017. The high-return Delaware Basin Wolfcamp Shale play, where EOG completed 116 net wells in 2017, will continue to be an area of focus in 2018. In the Second Bone Spring play, EOG holds approximately 289,000 net acres and completed 26 net wells in 2017. With over 1,800 estimated remaining net drilling locations, 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 20 net wells completed in 2017. EOG also announced the addition of a new high-return target in the Delaware Basin First Bone Spring oil play where it holds 100,000 net prospective acres. In 2017, EOG had consistent results in the First Bone Spring completing nine net wells and estimates that it has over 540 net locations remaining. Activity in 2018 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 230 net wells.

Activity in the Rocky Mountain area increased in 2017 with a focus on the completion of the remaining legacy drilled uncompleted wells (DUCs) in the Williston Basin Bakken and continued development of the Powder River and DJ Basins. In the Powder River Basin, EOG continued to expand its development programs in the Turner and Parkman formations, as well as test new horizons. With consistent results and strong returns in 2017, the Powder River Basin will again be a focal point for EOG in 2018. In the Wyoming DJ Basin, drilling, completion, and operating costs continued to be driven down and there is a significant high-return development program scheduled for 2018. Activity in the Williston Basin Bakken for 2017 was mainly limited to completing DUCs and will shift to drilling and completing new wells starting in the summer of 2018. EOG currently holds approximately 1.2 million net acres in the Rocky Mountain area.

In the Mid-Continent area, EOG proved the prospectivity of the Woodford Oil Window play with two net wells during 2017. EOG holds 50,000 net acres in the play with plans to continue development in 2018. Also in the area, EOG executed a joint venture agreement in the Western Anadarko Basin Marmaton Sand play. In 2017, EOG drilled 18 gross wells and completed 10 gross wells as operator of the joint venture. EOG divested 8,335 net acres with daily average production of 1,231 barrels of oil equivalent per day (Boed) in the Mid-Continent area. EOG plans to build on its initial success in the Woodford Oil Window with an expanded campaign of 25 net well completions in 2018. Continued development in the joint venture in the Western Anadarko Basin is also planned.

Total net production in 2017 from the Fort Worth Basin Barnett Shale averaged 3 MBbld of crude oil and condensate, 16 MBbld of NGLs and 94 MMcfd of natural gas. At year-end 2017, EOG held approximately 169,000 net acres in the Fort Worth Basin. In 2017, EOG divested 57,000 net acres and 137 net wells in the Fort Worth Basin Barnett Shale. Average daily production volumes associated with the sale were 5.5 MMcfd of natural gas.

In 2017, four DUCs were completed in the Marcellus Shale. Average initial production for the four wells was over 10 MMcfd. In 2018, EOG expects to complete 12 DUCs. EOG currently holds approximately 177,000 net acres with Marcellus and Utica Shale potential.

The Upper Gulf Coast area had limited drilling activity in 2017. EOG focused on portfolio enhancement through an active exploration and evaluation program. This is expected to continue in 2018.

In the South Texas area, EOG drilled four net liquids-rich natural gas wells in 2017, completed two and deferred additional completions until 2018. EOG expects to complete approximately 12 net liquids-rich natural gas wells in 2018 in the Frio and Vicksburg trends, where it holds approximately 238,000 net acres. In addition, exploration and evaluation efforts will continue in this region in 2018.

At December 31, 2017, EOG held approximately 2.2 million net undeveloped acres in the United States.

During 2017, 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 and the Permian Basin in West Texas and New Mexico. At December 31, 2017, EOG-owned natural gas processing capacity in the Eagle Ford and Barnett Shale totaled 325 MMcfd and 180 MMcfd, respectively.

Also in 2017, EOG continued to own its crude oil facilities near Stanley, North Dakota.

EOG operates its own sand mine and sand processing plant in Hood County, Texas, to reduce costs and to help fulfill EOG's sand needs for its well completion operations in Texas. Additionally, EOG owns a second Hood County sand processing plant, which processes sand sourced from the north Texas area, as needed.

In 2017, EOG processed sand from its Chippewa Falls, Wisconsin, sand plant for its well completion operations in North America and for sales to third parties.

EOG operated three sand unloading facilities to support well completions in the Delaware Basin, Eagle Ford and the Williston Basin Bakken in 2017.

Operations Outside the United States

EOG has operations offshore Trinidad, in the U.K. East Irish Sea, in the China Sichuan Basin and in Canada and is evaluating additional exploration, development and exploitation opportunities in these and other select international areas.

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 and Reggae Area (SMR);
- 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 (Petrotrin). In 2017, EOG's net production from Trinidad averaged approximately 313 MMcfd of natural gas and approximately 0.9 MBbld of crude oil and condensate.

In 2017, EOG completed and brought on-line two net wells finishing its program in the Sercan Area and drilled and completed five additional net wells in the Banyan and Osprey fields. EOG conducted a seismic survey in the U(a) Block, participated in a seismic survey program with a joint venture partner in the SMR area and signed a new multi-year contract under which EOG will supply future natural gas volumes to NGC beginning in 2019.

In 2018, EOG expects to focus on exploration and the acquisition of additional seismic. It is anticipated that EOG's 2018 Trinidad operations will supply approximately 356 MMcfd (266 MMcfd, net) of natural gas from its existing proved reserves. All of the natural gas produced from EOG's Trinidad operations in 2018 is expected to be supplied to NGC under various contracts with NGC. All crude oil and condensate produced from EOG's Trinidad operations in 2018 is expected to be supplied to Petrotrin under various contracts with Petrotrin.

At December 31, 2017, EOG held approximately 115,000 net undeveloped acres in Trinidad.

United Kingdom. EOG's subsidiary, EOG Resources United Kingdom Limited (EOGUK), owns a 25% non-operating working interest in a portion of Block 49/16a, located in the Southern Gas Basin of the North Sea. Production ceased at the end of the third quarter of 2015, and decommissioning began during the latter part of 2017.

In 2007, EOGUK was awarded a license for two blocks in the East Irish Sea – Blocks 110/7b and 110/12a. In 2009, EOGUK drilled a successful oil exploratory well in the East Irish Sea Block 110/12a. EOG began production from its 100% working interest East Irish Sea Conwy crude oil project in March 2016. Modifications to the nearby third-party-owned Douglas platform, which is used to process Conwy production, were completed in the first quarter of 2016 and acceptance and performance testing is ongoing. For the greater part of 2017, production in the Conwy was off-line due to facility improvements and operational issues. EOG resumed production in the first quarter of 2018.

In 2017, production averaged approximately 0.7 MBbld of crude oil, net, in the United Kingdom.

At December 31, 2017, EOG held approximately 4,000 net undeveloped acres in the United Kingdom.

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 drilled five natural gas wells and completed four of those wells in 2017 in the Sichuan Basin 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 complete a previously drilled well, drill five additional wells and complete four of those wells.

In 2017, production averaged approximately 17 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 2017, 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 2017, EOG's wellhead crude oil and condensate production was sold into local markets or transported either by pipeline or truck to downstream 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; Louisiana; and other points along the U.S. Gulf Coast. In 2018, the pricing mechanism for such production is expected to remain the same.

In 2017, 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 2018, the pricing mechanism for such production is expected to remain the same.

In 2017, EOG's United States wellhead natural gas production was sold into local markets or transported by pipeline to downstream markets. Pricing was based on the spot market price at the ultimate sales point. In 2018, the pricing mechanism for such production is expected to remain the same.

In 2017, 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. The pricing mechanisms for these contracts in Trinidad are expected to remain the same in 2018.

In December 2014, EOG put in place arrangements to market and sell its U.K. wellhead crude oil production from the Conwy field, which commenced production in March 2016. The crude oil sales are based on a Dated Brent price or other market prices, as applicable.

In 2017, 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 2018.

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 2017, 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, 2017, 2016 and 2015. 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	**2017**	**2016**	**2015**
Crude Oil and Condensate Volumes (MMBbl) [(1)]			
United States:			
Eagle Ford	57.4	60.7	66.3
Delaware Basin	31.6	17.0	9.8
Other	33.2	24.2	27.3
United States	122.2	101.9	103.4
Trinidad	0.3	0.3	0.3
Other International [(2)]	0.2	1.2	0.1
Total	**122.7**	**103.4**	**103.8**
Natural Gas Liquids Volumes (MMBbl) [(1)]			
United States:			
Eagle Ford	9.4	10.0	9.9
Delaware Basin	8.8	5.8	3.1
Other	14.1	14.1	15.1
United States	32.3	29.9	28.1
Other International [(2)]	—	—	—
Total	**32.3**	**29.9**	**28.1**
Natural Gas Volumes (Bcf) [(1)]			
United States:			
Eagle Ford	55	59	65
Delaware Basin	81	50	27
Other	143	187	231
United States	279	296	323
Trinidad	114	125	127
Other International [(2)]	9	9	12
Total	**402**	**430**	**462**
Crude Oil Equivalent Volumes (MMBoe) [(3)]			
United States:			
Eagle Ford	76.0	80.6	87.1
Delaware Basin	53.9	31.2	17.4
Other	71.2	69.3	80.9
United States	201.1	181.1	185.4
Trinidad	19.4	21.1	21.6
Other International [(2)]	1.8	2.8	1.9
Total	**222.3**	**205.0**	**208.9**

Year Ended December 31	2017	2016	2015
Average Crude Oil and Condensate Prices ($/Bbl) [4]			
United States	$ 50.91	$ 41.84	$ 47.55
Trinidad	42.30	33.76	39.51
Other International [2]	57.20	36.72	57.32
Composite	**50.91**	**41.76**	**47.53**
Average Natural Gas Liquids Prices ($/Bbl) [4]			
United States	$ 22.61	$ 14.63	$ 14.50
Other International [2]	—	—	4.61
Composite	**22.61**	**14.63**	**14.49**
Average Natural Gas Prices ($/Mcf) [4]			
United States	$ 2.20	$ 1.60	$ 1.97
Trinidad	2.38	1.88	2.89
Other International [2]	3.89	3.64	5.05
Composite	**2.29**	**1.73**	**2.30**

(1) Million barrels or billion cubic feet, as applicable.
(2) Other International includes EOG's United Kingdom, China, Canada and Argentina operations. 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).

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 and strong governmental relationships in countries 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 in the United States 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 2017.

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 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 June 2017, the U.S. EPA proposed to stay certain requirements of that rule for two years.

Also, 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, in June 2017, the U.S. President indicated that the U.S. will withdraw from the Paris Agreement.

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 is typically more than 99% water and sand, and less than 1% of highly diluted chemical additives; lists of the chemical additives most typically 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 percentage 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 regularly conducts audits 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 volatile organic compounds (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 June 2017, the U.S. EPA proposed to stay certain requirements of that rule for two years.

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. In December 2017, the BLM temporarily suspended or delayed certain requirements of that rule until January 17, 2019. 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, the United Kingdom, China and Canada. 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. Consistent with EOG's 2016 production, crude oil and condensate and NGL production comprised a larger portion of EOG's production mix in 2017 than in prior years. Average crude oil and condensate prices received by EOG for production in the United States increased 22% in 2017 and decreased 12% in 2016 and 49% in 2015, each as compared to the immediately preceding year. Average NGL prices received by EOG for production in the United States increased 55% in 2017 and 1% in 2016, and decreased 54% in 2015, 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 38% increase in the average wellhead natural gas price received by EOG for production in the United States in 2017, a 19% decrease in 2016 and a 50% decrease in 2015, each as compared to the immediately preceding year.

Due to the many uncertainties associated with the world political 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 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.

Including the impact of EOG's 2018 crude oil derivative contracts (exclusive of basis swaps) and based on EOG's tax position, EOG's price sensitivity in 2018 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 $82 million for net income and $106 million for cash flows from operating activities. Including the impact of EOG's 2018 natural gas derivative contracts (exclusive of call options) and based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2018 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 $22 million for net income and $29 million for cash flows from operating activities. For a summary of EOG's financial commodity derivative contracts through February 20, 2018, 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, 2017, 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 20, 2018, 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 conditions. 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 27, 2018) are as follows:

Name	**Age**	**Position**
William R. Thomas	65	Chairman of the Board and Chief Executive Officer
Gary L. Thomas	68	President
Lloyd W. Helms, Jr.	60	Chief Operating Officer
David W. Trice	47	Executive Vice President, Exploration and Production
Ezra Y. Yacob	41	Executive Vice President, Exploration and Production
Timothy K. Driggers	56	Executive Vice President and Chief Financial Officer
Michael P. Donaldson	55	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.

Gary L. Thomas was elected President in December 2017. Prior to that, he served as President and Chief Operating Officer from March 2015 to December 2017. He was elected Chief Operating Officer in September 2011, Executive Vice President, North America Operations in May 1998, Executive Vice President, Operations in May 2002, and served as Senior Executive Vice President, Operations from February 2007 to September 2011. He also previously served as Senior Vice President and General Manager of EOG’s Midland, Texas, office. Mr. Thomas joined a predecessor of EOG in July 1978. As previously announced, Mr. Thomas is expected to retire from EOG by year-end 2018.

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.

David W. Trice was elected Executive Vice President, Exploration and Production in August 2013. He served as Vice President and General Manager of EOG's Fort Worth, Texas, office from May 2010 to August 2013. Prior to that, he served in various geological and management positions at EOG. Mr. Trice joined EOG in November 1999.

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 factors that can or could cause these price fluctuations are:

- domestic and worldwide supplies of crude oil, NGLs and natural gas;
- the actions of other crude oil exporting nations, including the Organization of Petroleum Exporting Countries;
- domestic and international drilling activity;
- the price and quantity of imported and exported crude oil, NGLs and natural gas;
- the level of consumer demand;
- weather conditions and changes in weather patterns;
- the availability, proximity and capacity of appropriate transportation facilities, gathering, processing and compression facilities and refining facilities;
- worldwide economic and political conditions, including political instability or armed conflict in oil and gas producing regions;
- the price and availability of, and demand for, competing energy sources, including alternative energy sources;
- the nature and extent of governmental regulation, including environmental 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

- the effect of worldwide energy conservation measures and alternative fuel requirements.

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 during 2016. While crude oil, natural gas and NGL prices improved notably during 2017, the above-described factors and the volatility of commodity prices make it difficult to predict future crude oil, natural gas and NGL prices. As a result, there can be no assurance of further commodity price increases, nor can there be any assurance that current commodity prices will be sustained or that the prices for crude oil, natural gas and/or NGLs will not again 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, our ability to 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 declines in the prices of these commodities can render uneconomic a significant portion of our exploration, development and exploitation projects, resulting in our having to make significant 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 significant additional 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 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, 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 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 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 conditions, such as winter storms, flooding, tropical storms and hurricanes, and other natural disasters;
- fires and explosions;
- terrorism, vandalism and physical, electronic and cyber security breaches;
- formations with abnormal or unexpected pressures;
- leaks or spills in connection with, or associated with, the gathering, processing, compression 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 clean-up 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. 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 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 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 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 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 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, 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. In June 2017, the U.S. EPA proposed to stay certain requirements of that rule for two years. 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, in June 2017, the U.S. President indicated that the U.S. will withdraw from the Paris Agreement.

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 December 2017, the BLM temporarily suspended or delayed certain requirements of that rule until January 17, 2019. 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 may change over time, and additional regulatory guidance or changes in EOG's assumptions and interpretations in respect of the recently passed comprehensive tax reform bill could adversely affect our cash flows, results of operations and financial condition.

On December 22, 2017, the U.S. President signed into law a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the TCJA) that significantly changes the Internal Revenue Code of 1986, as amended. The TCJA, among other things, (i) permanently reduces the U.S. corporate income tax rate; (ii) repeals the corporate alternative minimum tax (AMT); (iii) provides for the refund of AMT credits over a four-year period beginning in 2018; (iv) revises the U.S. federal taxation of foreign earnings; (v) imposes a tax on the deemed repatriation of existing foreign earnings that is payable over an eight-year period beginning in 2017; and (vi) provides for other changes to the taxation of corporations, including changes to cost recovery rules, the utilization of net operating losses, and the deductibility of interest expense, each of which may impact the taxation of oil and gas companies. The TCJA is complex and far-reaching and we cannot predict with certainty the resulting impact its enactment will have on us. The ultimate impact of the TCJA may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued, and any such changes in interpretations or assumptions could materially and adversely affect our cash flows, results of operations and financial condition. See Note 6 to Consolidated Financial Statements for additional information.

In addition, from time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including the elimination of the immediate deduction for intangible drilling and development costs. While these specific changes are not included in the TCJA, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of certain U.S. federal tax deductions, as well as any other changes to, or the imposition of new, federal, state, local or non-U.S. taxes (including the imposition of, or increases in, production, severance or similar taxes), could 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, 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 and a depressed commodity price environment may increase the interest rates that lenders and commercial paper investors require us to pay and adversely affect our ability to finance our capital expenditures through equity or debt offerings or other borrowings. 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. In addition, 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.

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. 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 or capacity of gathering, processing, compression and transportation 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 and strong governmental relationships in countries 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 and continual reassessment of the viability of production under varying economic conditions.

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 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 significant 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, our exploration, exploitation and development activities and equipment can be adversely affected by extreme weather conditions, 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 conditions 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 and transportation facilities and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. Such extreme weather conditions 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 price swap, option, swaption, collar and basis swap 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 20, 2018, our forecasted crude oil production for 2018 is approximately 34% hedged at approximately $60.04 per barrel (excluding basis swap contracts) and our forecasted natural gas production for 2018 is approximately 12% hedged at approximately $2.96 per million British thermal units (excluding call option contracts). As a result, a portion of our forecasted production for 2018 remains unhedged and subject to fluctuating market prices. If we are ultimately unable to hedge additional production volumes for 2018 and beyond, we will be impacted by further 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 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 (e.g., as a result of Great Britain's June 2016 vote to leave the European Union).

Our international operations may also be adversely affected by U.S. laws and policies affecting foreign trade and taxation, including 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, 2017, 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.

As a producer of crude oil and natural gas, 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, 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 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. 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 developed and undeveloped acreage at December 31, 2017. 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	2,884,046	2,048,525	2,996,627	2,152,154	5,880,673	4,200,679
Trinidad	79,277	67,474	201,435	115,274	280,712	182,748
United Kingdom	11,830	5,603	12,683	4,248	24,513	9,851
China	130,548	130,548	—	—	130,548	130,548
Canada	40,000	35,771	105,560	98,436	145,560	134,207
Total	3,145,701	2,287,921	3,316,305	2,370,112	6,462,006	4,658,033

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 0.2 million net acres will expire in 2018, 0.3 million net acres will expire in 2019 and 0.4 million net acres will expire in 2020 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, 2017, 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 509 wells in which we hold a royalty interest.

	Crude Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	8,039	5,925	5,378	3,729	13,417	9,654
Trinidad	13	10	44	36	57	46
United Kingdom	3	3	—	—	3	3
China	—	—	33	33	33	33
Canada	—	—	24	23	24	23
Total [(1)]	8,055	5,938	5,479	3,821	13,534	9,759

(1) EOG operated 10,984 gross and 9,379 net producing crude oil and natural gas wells at December 31, 2017. Gross crude oil and natural gas wells include 389 wells with multiple completions.

Drilling and Acquisition Activities. During the years ended December 31, 2017, 2016 and 2015, EOG expended $4.4 billion, $6.4 billion and $4.9 billion, respectively, for exploratory and development drilling, facilities and acquisition of leases and producing properties, including asset retirement obligations of $56 million, $(20) million and $53 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, 2017, 2016 and 2015:

	Gross Development Wells Completed				Gross Exploratory Wells Completed			
	Crude Oil	Natural Gas	Dry Hole	Total	Crude Oil	Natural Gas	Dry Hole	Total
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
2015								
United States	494	16	9	519	2	—	—	2
Trinidad	—	3	—	3	—	1	—	1
China	—	—	—	—	—	3	2	5
Total	494	19	9	522	2	4	2	8

The following tables set forth the results of the net crude oil and natural gas wells completed for the years ended December 31, 2017, 2016 and 2015:

	Net Development Wells Completed				Net Exploratory Wells Completed			
	Crude Oil	Natural Gas	Dry Hole	Total	Crude Oil	Natural Gas	Dry Hole	Total
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
2015								
United States	457	14	8	479	2	—	—	2
Trinidad	—	2	—	2	—	1	—	1
China	—	—	—	—	—	3	2	5
Total	457	16	8	481	2	4	2	8

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, 2017, 2016 and 2015:

	Wells in Progress at End of Period					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
United States	247	208	237	194	516	429
Trinidad	—	—	1	1	—	—
China	1	1	—	—	—	—
Total	248	209	238	195	516	429

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). The following table sets forth EOG's DUCs, for which proved undeveloped reserves had been booked, as of the end of each period.

	Drilled Uncompleted Wells at End of Period					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
United States	147	121	173	137	406	333
China	1	1	—	—	—	—
Total	148	122	173	137	406	333

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, 2017, there were approximately 67 MMBoe of net proved undeveloped reserves 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.

EOG acquired wells, which includes the acquisition of additional interests in certain wells in which EOG previously owned an interest, as set out in the tables below for the years ended December 31, 2017, 2016 and 2015:

	Gross Acquired Wells			Net Acquired Wells		
	Crude Oil	Natural Gas	Total	Crude Oil	Natural Gas	Total
2017						
United States	12	3	15	17	20	37
Total	12	3	15	17	20	37
2016						
United States	4,112	4,144	8,256	1,261	2,327	3,588
Total	4,112	4,144	8,256	1,261	2,327	3,588
2015						
United States	24	—	24	23	—	23
Total	24	—	24	23	—	23

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, 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.

As previously reported by EOG Resources, Inc. (EOG) in its Forms 10-Q for the quarterly periods ended June 30, 2017 and September 30, 2017, EOG executed a consent decree with the North Dakota Department of Health (NDDOH) in July 2017, regarding alleged violations of North Dakota's air pollution control laws and related provisions of the federal Clean Air Act. The consent decree was subsequently executed by the NDDOH and, in August 2017, the North Dakota District Court for the South Central Judicial District issued its order approving the consent decree and resolving the alleged violations raised therein. EOG's consent decree generally follows the same format as the consent decrees that the NDDOH has negotiated with other North Dakota operators.

As previously reported, the consent decree provided for a base penalty of $400,000. The consent decree further provided that the base penalty could be reduced by up to 60 percent in respect of voluntary leak detection and repair (LDAR) efforts by EOG and EOG's development and submission of a quality assurance/quality control (QA/QC) plan to assist with minimizing air emissions. Additionally, pursuant to the terms of the consent decree, EOG was eligible to fund a supplemental environmental project (SEP) to offset up to 50 percent of the final penalty amount.

EOG qualified for all of the available penalty reductions and the SEP-related offset. After taking into account such reductions and the SEP-related offset, EOG paid a final penalty of $90,375 to the NDDOH in November 2017.

The penalty amount paid to the NDDOH, the expenditures resulting from EOG's LDAR efforts and development and submission of a QA/QC plan and the amount funded for the SEP has not had, and is not expected to have, a material adverse effect on EOG's financial position, results of operations or cash flows.

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." The following table sets forth, for the periods indicated, the high and low sales price per share for EOG's common stock, as reported by the NYSE, and the amount of the cash dividend declared per share. The quarterly cash dividend on EOG's common stock has historically been declared in the quarter immediately preceding the quarter of payment and paid on January 31, April 30, July 31 and October 31 of each year (or, if such day is not a business day, the immediately preceding business day).

	Price Range		
	High	Low	Dividend Declared
2017			
First Quarter	$ 106.79	$ 92.91	$ 0.1675
Second Quarter	100.53	85.88	0.1675
Third Quarter	98.37	81.99	0.1675
Fourth Quarter	109.66	94.87	0.1675
2016			
First Quarter	$ 77.70	$ 57.15	$ 0.1675
Second Quarter	86.87	69.66	0.1675
Third Quarter	97.20	78.04	0.1675
Fourth Quarter	109.37	88.94	0.1675

As of February 14, 2018, there were approximately 2,000 record holders and approximately 363,000 beneficial owners of EOG's common stock.

On February 27, 2018, EOG's Board increased the quarterly cash dividend on the common stock by 10% from the current $0.1675 per share to $0.1850 per share, effective beginning with the dividend to be paid on April 30, 2018, to stockholders of record as of April 16, 2018. EOG currently intends to continue to pay quarterly cash dividends on its outstanding shares of common stock in the future. However, the determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other factors, the financial condition, cash flows, level of exploration and development expenditure opportunities and future business prospects of EOG.

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, 2017 - October 31, 2017	60,551	$ 97.33	—	6,386,200
November 1, 2017 - November 30, 2017	39,073	$ 104.91	—	6,386,200
December 1, 2017 - December 31, 2017	28,144	$ 103.80	—	6,386,200
Total	127,768	$ 101.07		

(1) The 127,768 total shares for the quarter ended December 31, 2017, and the 685,650 total shares for the full year 2017, 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, performance stock 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 2017, EOG did not repurchase any shares under the Board-authorized repurchase program.

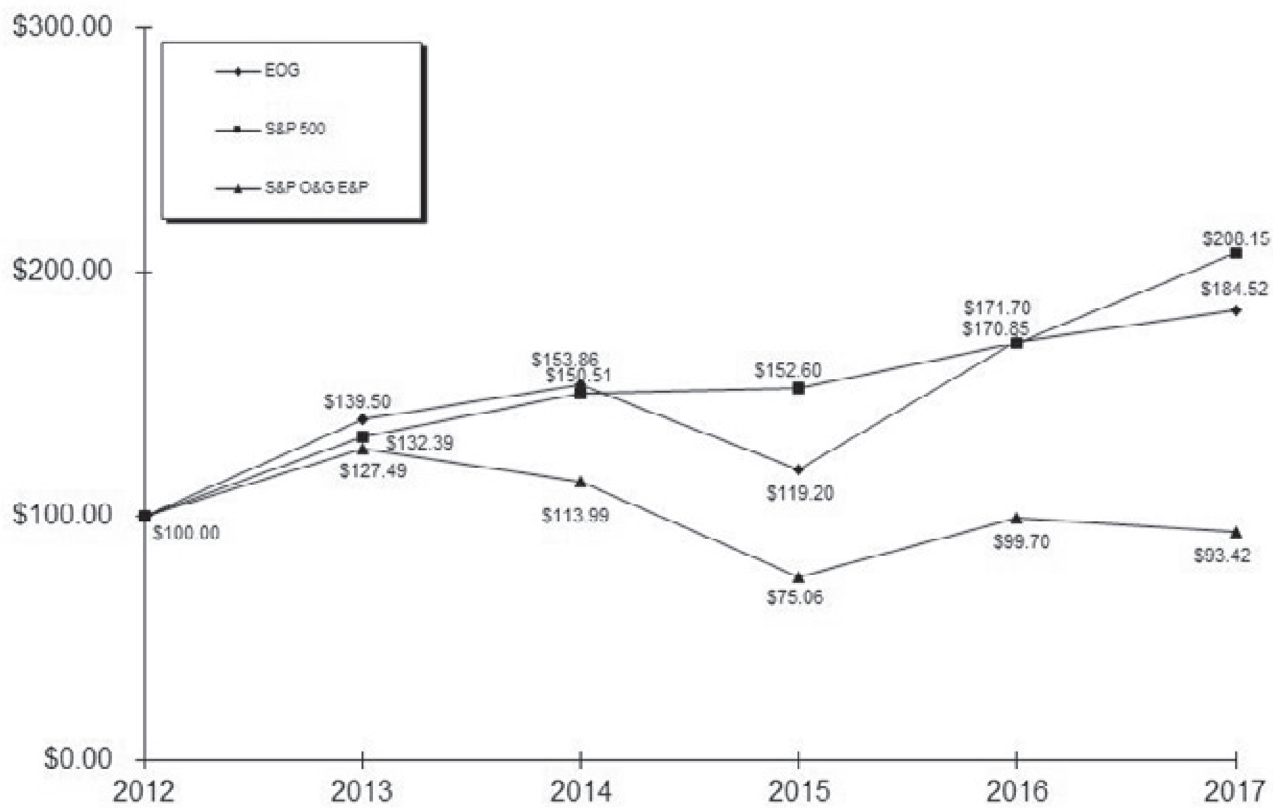
Comparative Stock Performance

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, 2012 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, 2017)



	2012	2013	2014	2015	2016	2017
EOG	$ 100.00	$ 139.50	$ 153.86	$ 119.20	$ 171.70	$ 184.52
S&P 500	$ 100.00	$ 132.39	$ 150.51	$ 152.60	$ 170.85	$ 208.15
S&P O&G E&P	$ 100.00	$ 127.49	$ 113.99	$ 75.06	$ 99.70	$ 93.42

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	**2017**	**2016**	**2015**	**2014**	**2013**
Statement of Income Data:					
Net Operating Revenues and Other	$ 11,208,320	$ 7,650,632	$ 8,757,428	$ 18,035,340	$ 14,487,118
Operating Income (Loss)	$ 926,402	$ (1,225,281)	$ (6,686,079)	$ 5,241,823	$ 3,675,211
Net Income (Loss)	$ 2,582,579	$ (1,096,686)	$ (4,524,515)	$ 2,915,487	$ 2,197,109
Net Income (Loss) Per Share					
Basic	$ 4.49	$ (1.98)	$ (8.29)	$ 5.36	$ 4.07
Diluted	$ 4.46	$ (1.98)	$ (8.29)	$ 5.32	$ 4.02
Dividends Per Common Share	$ 0.670	$ 0.670	$ 0.670	$ 0.585	$ 0.375
Average Number of Common Shares					
Basic	574,620	553,384	545,697	543,443	540,341
Diluted	578,693	553,384	545,697	548,539	546,227

At December 31	**2017**	**2016**	**2015**	**2014**	**2013**
Balance Sheet Data:					
Total Property, Plant and Equipment, Net	$ 25,665,037	$ 25,707,078	$ 24,210,721	$ 29,172,644	$ 26,148,836
Total Assets [(1)] [(2)]	29,833,078	29,299,201	26,834,908	34,758,599	30,325,569
Total Debt [(1)]	6,387,071	6,986,358	6,655,490	5,905,846	5,909,157
Total Stockholders' Equity	16,283,273	13,981,581	12,943,035	17,712,582	15,418,459

(1) Includes reclassification of $4.8 million, $4.1 million and $4.1 million in unamortized debt issuance costs from "Other Assets" to "Long-Term Debt" for years ending December 31, 2015, 2014, and 2013, respectively (see Note 1 to Consolidated Financial Statements).

(2) Includes reclassification of $160 million, $136 million and $245 million from deferred tax liabilities to deferred tax assets for the years ending December 31, 2016, 2015 and 2013, respectively (see Note 1 to Consolidated Financial Statements).

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, the United Kingdom 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 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 prudent and safe operations is also an important goal in the implementation of EOG's strategy.

EOG realized net income of $2,583 million during 2017 as compared to a net loss of $1,097 million for 2016. At December 31, 2017, EOG's total estimated net proved reserves were 2,527 million barrels of oil equivalent (MMBoe), an increase of 380 MMBoe from December 31, 2016. During 2017, net proved crude oil and condensate and natural gas liquids (NGLs) reserves increased by 223 million barrels (MMBbl), and net proved natural gas reserves increased by 945 billion cubic feet or 158 MMBoe, in each case from December 31, 2016.

Operations

Several important developments have occurred since January 1, 2017.

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 2017, EOG continued to focus on increasing drilling, completion and operating efficiencies using precision lateral targeting and advanced completion methods and reducing operating and capital costs through efficiency improvements and service cost reductions. These efficiency gains along with certain realized lower service costs resulted in lower drilling and completion costs and decreased operating expenses during 2017. EOG continues to look for opportunities to add drilling inventory through leasehold acquisitions, farm-ins, exchanges or tactical acquisitions and to evaluate certain potential crude oil and liquids-rich natural gas exploration and development prospects. 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 2017 as compared to 73% for 2016. During 2017, 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. In 2017, EOG completed and brought on-line two net wells finishing its program in the Sercan Area and drilled and completed five additional net wells in the Banyan and Osprey fields. EOG conducted a seismic survey in the U(a) Block, participated in a seismic survey program with a joint venture partner in the Ska, Mento and Reggae area and signed a new multi-year contract under which EOG will supply future natural gas volumes to NGC beginning in 2019.

Other International. In the United Kingdom, EOG produces crude oil from its 100% working interest East Irish Sea Conwy project. Beginning in the second quarter of 2017, production in the Conwy was off-line due to facility improvements and operational issues. EOG resumed production in the first quarter of 2018.

In the Sichuan Basin, Sichuan Province, China, EOG drilled five natural gas wells and completed four of those wells in 2017 as part of the continuing development of the Bajiaochang Field, which natural gas is sold under a long-term contract to PetroChina.

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.

Tax Cuts and Jobs Act

In December 2017, the United States enacted the Tax Cuts and Jobs Act (TCJA), which made significant changes to United States federal income tax law. Under the Income Taxes Topic of the Accounting Standards Codification, the effects of new legislation are recognized upon enactment. Accordingly, recognition of the tax effects of the TCJA is required in the consolidated financial statements for the fiscal year ended December 31, 2017. As more fully described in the Notes to Consolidated Financial Statements, the TCJA made several changes to United States corporate income tax laws, some of which will have a material impact on EOG's tax provision for 2017 and subsequent periods, including the reduction in the statutory tax rate from 35 percent to 21 percent, a one-time tax on the deemed repatriation of foreign earnings and the conversion to the territorial system of taxation of foreign earnings. The TCJA is expected to reduce EOG's effective tax rate in 2018 and subsequent years, though the ultimate impact on its worldwide effective tax rate will depend on the percentage of pretax income generated by EOG in the United States as compared to its other jurisdictions.

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 28% at December 31, 2017 and 33% at December 31, 2016. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

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

On February 15, 2017, the Board of Directors 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.

During 2017, EOG funded $4.6 billion ($282 million of which was non-cash property exchanges) in exploration and development and other property, plant and equipment expenditures (excluding asset retirement obligations), repaid $600 million aggregate principal amount of long-term debt, paid $387 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 2018 capital expenditures are estimated to range from approximately $5.4 billion to $5.8 billion, excluding acquisitions. The majority of 2018 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.

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

Results of Operations

The following review of operations for each of the three years in the period ended December 31, 2017, should be read in conjunction with the consolidated financial statements of EOG and notes thereto beginning on page F-1.

Net Operating Revenues and Other

During 2017, net operating revenues increased $3,557 million, or 47%, to $11,208 million from $7,651 million in 2016. Total wellhead revenues, which are revenues generated from sales of EOG's production of crude oil and condensate, NGLs and natural gas, increased $2,411 million, or 44%, to $7,908 million in 2017 from $5,497 million in 2016. Revenues from the sales of crude oil and condensate and NGLs in 2017 were approximately 88% of total wellhead revenues compared to 86% in 2016. During 2017, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $20 million compared to net losses of $100 million in 2016. Gathering, processing and marketing revenues increased $1,332 million during 2017, to $3,298 million from $1,966 million in 2016. Net losses on asset dispositions of $99 million in 2017 were primarily as a result of sales of producing properties and acreage in Texas and the Rocky Mountain area compared to net gains on asset dispositions of $206 million in 2016.

Wellhead volume and price statistics for the years ended December 31, 2017, 2016 and 2015 were as follows:

Year Ended December 31		2017		2016		2015
Crude Oil and Condensate Volumes (MBbld) (1)						
United States		335.0		278.3		283.3
Trinidad		0.9		0.8		0.9
Other International (2)		0.8		3.4		0.2
Total		**336.7**		**282.5**		**284.4**
Average Crude Oil and Condensate Prices ($/Bbl) (3)						
United States	$	50.91	$	41.84	$	47.55
Trinidad		42.30		33.76		39.51
Other International (2)		57.20		36.72		57.32
Composite		**50.91**		**41.76**		**47.53**
Natural Gas Liquids Volumes (MBbld) (1)						
United States		88.4		81.6		76.9
Other International (2)		—		—		0.1
Total		**88.4**		**81.6**		**77.0**
Average Natural Gas Liquids Prices ($/Bbl) (3)						
United States	$	22.61	$	14.63	$	14.50
Other International (2)		—		—		4.61
Composite		**22.61**		**14.63**		**14.49**
Natural Gas Volumes (MMcfd) (1)						
United States		765		810		886
Trinidad		313		340		349
Other International (2)		25		25		30
Total		**1,103**		**1,175**		**1,265**
Average Natural Gas Prices ($/Mcf) (3)						
United States	$	2.20	$	1.60	$	1.97
Trinidad		2.38		1.88		2.89
Other International (2)		3.89		3.64		5.05
Composite		**2.29**		**1.73**		**2.30**
Crude Oil Equivalent Volumes (MBoed) (4)						
United States		551.0		494.9		507.9
Trinidad		53.0		57.5		59.1
Other International (2)		4.9		7.6		5.2
Total		**608.9**		**560.0**		**572.2**
Total MMBoe (4)		**222.3**		**205.0**		**208.9**

(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 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) 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.

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 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 are 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 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).

2016 compared to 2015. Wellhead crude oil and condensate revenues in 2016 decreased $618 million, or 13%, to $4,317 million from $4,935 million in 2015, due primarily to a lower composite average wellhead crude oil and condensate price. EOG's composite wellhead crude oil and condensate price for 2016 decreased 12% to $41.76 per barrel compared to $47.53 per barrel in 2015. Wellhead crude oil and condensate deliveries in 2016 decreased 1% to 283 MBbld as compared to 284 MBbld in 2015. The decreased production was primarily due to lower production in the Eagle Ford and the Rocky Mountain area, largely offset by increased production in the Permian Basin.

NGL revenues in 2016 increased $29 million, or 7%, to $437 million from $408 million in 2015, due to an increase of 5 MBbld, or 6%, in NGL deliveries primarily as a result of increased production in the Permian Basin.

Wellhead natural gas revenues in 2016 decreased $319 million, or 30%, to $742 million from $1,061 million in 2015, primarily due to a lower composite wellhead natural gas price ($246 million) and a decrease in wellhead natural gas deliveries ($73 million). EOG's composite average wellhead natural gas price decreased 25% to $1.73 per Mcf in 2016 compared to $2.30 per Mcf in 2015. Natural gas deliveries in 2016 decreased 7% to 1,175 MMcfd as compared to 1,265 MMcfd in 2015. The decrease in production was primarily due to decreased production in the United States (76 MMcfd). The decreased production was due primarily to lower volumes in the Fort Worth Barnett Shale, Upper Gulf Coast and South Texas areas, largely resulting from asset sales in these regions during the year, partially offset by increased production of associated gas in the Permian Basin and the acquisition of the Yates Entities.

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. During 2015, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $62 million, which included net cash received from settlements of crude oil and natural gas financial derivative contracts of $730 million.

Gathering, processing and marketing revenues less marketing costs in 2016 increased $91 million compared to 2015, primarily due to higher margins on crude oil marketing activities and on sand sales.

Operating and Other Expenses

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 "Net 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 $1,045 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 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 $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 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 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 represent operating and maintenance expenses and administrative expenses associated with operating EOG's gathering and processing assets and certain charges from third-party processors.

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.

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, 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 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 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. See Note 6 to Consolidated Financial Statements for a further description of the income tax changes enacted by TCJA affecting EOG.

2016 compared to 2015. During 2016, operating expenses of $8,876 million were $6,568 million lower than the $15,444 million incurred during 2015. Operating expenses for 2015 included impairments of proved properties; other property, plant and equipment; and other assets of $6,326 million primarily due to commodity price declines. The following table presents the costs per barrel of oil equivalent (Boe) for the years ended December 31, 2016 and 2015:

	2016	2015
Lease and Well	$ 4.53	$ 5.66
Transportation Costs	3.73	4.07
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	16.77	15.27
Other Property, Plant and Equipment	0.57	0.59
General and Administrative (G&A)	1.93	1.75
Net Interest Expense	1.37	1.14
Total (1)	**$ 28.90**	**$ 28.48**

(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 2016 compared to 2015 are set forth below. See "Net Operating Revenues and Other" above for a discussion of production volumes.

Lease and well expenses of $927 million in 2016 decreased $255 million from $1,182 million in 2015 primarily due to lower operating and maintenance costs ($218 million) and lower lease and well administrative expenses ($35 million), both in the United States.

Transportation costs of $764 million in 2016 decreased $85 million from $849 million in 2015 primarily due to decreased transportation costs in the Rocky Mountain area ($55 million), the Barnett Shale ($21 million), the Eagle Ford ($19 million) and the Upper Gulf Coast region ($10 million) primarily due to lower production and service cost reductions in these regions, partially offset by increased transportation costs related to higher production from the Permian Basin ($18 million).

DD&A expenses in 2016 increased $239 million to $3,553 million from $3,314 million in 2015. DD&A expenses associated with oil and gas properties in 2016 were $247 million higher than in 2015 primarily due to higher unit rates in the United States ($300 million) and China ($3 million) and commencement of crude oil production from the Conwy field in the United Kingdom ($22 million), partially offset by a decrease in production in the United States ($68 million) and Trinidad ($4 million) and lower unit rates in Trinidad ($6 million). Unit rates in the United States increased primarily due to downward reserve revisions at December 31, 2015, as a result of lower commodity prices.

G&A expenses of $395 million in 2016 increased $28 million from $367 million in 2015 primarily due to employee-related expenses in connection with certain voluntary retirements and costs related to the Yates transaction.

Net interest expense of $282 million in 2016 was $45 million higher than 2015 primarily due to interest incurred on the notes issued in January 2016 ($43 million), as well as a decrease in capitalized interest ($10 million). This was partially offset by the reduction of interest expense related to the debt repaid in February 2016 and June 2015 ($16 million).

Gathering and processing costs decreased $23 million to $123 million in 2016 compared to $146 million in 2015 due to decreased activities in the Eagle Ford ($16 million) and the Barnett Shale ($7 million).

Exploration costs of $125 million in 2016 decreased $24 million from $149 million in 2015 primarily due to decreased geological and geophysical expenditures ($15 million) and lower exploration administrative expenses ($14 million), partially offset by higher delay rentals ($5 million), all in the United States.

The following table represents impairments for the years ended December 31, 2016 and 2015 (in millions):

	2016	**2015**
Proved properties	$ 116	$ 6,326
Unproved properties	291	288
Other property, plant and equipment	14	—
Inventories	61	—
Firm commitment contracts	138	—
Total	**$ 620**	**$ 6,614**

Impairments of proved properties were primarily due to the write-down to fair value of divested legacy natural gas assets in 2016 and primarily due to commodity price declines in 2015. Impairments of unproved properties were primarily due to higher amortization rates being applied to undeveloped leasehold costs in response to the significant decrease in commodity prices and an increase in EOG's estimates of undeveloped properties not expected to be developed before lease expiration in 2016 and 2015. 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 2016 decreased $72 million to $350 million (6.4% of wellhead revenues) from $422 million (6.6% of wellhead revenues) in 2015. The decrease in taxes other than income was primarily due to decreases in ad valorem/property taxes ($49 million) and in severance/production taxes ($34 million), primarily as a result of decreased wellhead revenues, both in the United States. These decreases were partially offset by a decrease in credits available to EOG in 2016 for Texas high-cost gas severance tax rate reductions ($12 million).

Other expense, net, was $51 million in 2016 compared to other income, net, of $2 million in 2015. The increase of $53 million was primarily due to an increase in foreign currency transaction losses and increased deferred compensation expense.

EOG recognized an income tax benefit of $461 million in 2016 compared to an income tax benefit of $2,397 million in 2015, primarily due to a decrease in pretax loss resulting from the absence of certain 2015 impairments. The net effective tax rate for 2016 decreased to 30% from 35% in the prior year primarily due to additional Trinidad taxes resulting from a tax settlement reached in the second quarter of 2016 ($43 million).

Capital Resources and Liquidity

Cash Flow

The primary sources of cash for EOG during the three-year period ended December 31, 2017, 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; repayments of debt; dividend payments to stockholders; and purchases of treasury stock in connection with stock compensation plans.

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).

2016 compared to 2015. Net cash provided by operating activities of $2,359 million in 2016 decreased $1,236 million from $3,595 million in 2015 primarily reflecting a decrease in wellhead revenues ($907 million), an unfavorable change in the net cash received from the settlement of financial commodity derivative contracts ($752 million), unfavorable changes in working capital and other assets and liabilities ($197 million) and an increase in net cash paid for interest expense ($30 million), partially offset by a decrease in cash operating expenses ($442 million) and a decrease in net cash paid for income taxes ($80 million).

Net cash used in investing activities of $1,253 million in 2016 decreased by $4,067 million from $5,320 million in 2015 primarily due to a decrease in additions to oil and gas properties ($2,235 million); an increase in proceeds from asset sales ($926 million); favorable changes in working capital associated with investing activities ($656 million); a decrease in additions to other property, plant and equipment ($195 million); and net cash received from the Yates transaction ($55 million).

Net cash used for financing activities of $243 million in 2016 included repayments of long-term debt ($564 million), cash dividend payments ($373 million), net commercial paper repayments ($260 million) and purchases of treasury stock in connection with stock compensation plans ($82 million). Cash provided by financing activities in 2016 included net proceeds from the issuance of the Notes ($991 million), excess tax benefits from stock-based compensation ($29 million) and proceeds from stock options exercised and employee stock purchase plan activity ($23 million).

Total Expenditures

The table below sets out components of total expenditures for the years ended December 31, 2017, 2016 and 2015 (in millions):

	2017	2016	2015
Expenditure Category			
Capital			
Exploration and Development Drilling	$ 3,132	$ 1,957	$ 3,289
Facilities	575	375	765
Leasehold Acquisitions (1)	427	3,217	134
Property Acquisitions (2)	73	749	481
Capitalized Interest	27	31	42
Subtotal	4,234	6,329	4,711
Exploration Costs	145	125	149
Dry Hole Costs	5	11	15
Exploration and Development Expenditures	4,384	6,465	4,875
Asset Retirement Costs	56	(20)	53
Total Exploration and Development Expenditures	4,440	6,445	4,928
Other Property, Plant and Equipment (3)	173	109	288
Total Expenditures	**$ 4,613**	**$ 6,554**	**$ 5,216**

(1) Leasehold acquisitions included $256 million in 2017 related to non-cash property exchanges and $3,115 million in 2016 related to the Yates transaction.
(2) Property acquisitions included $26 million in 2017 related to non-cash property exchanges and $735 million in 2016 related to the Yates transaction.
(3) Other property, plant and equipment included $17 million in 2016 related to the Yates transaction.

Exploration and development expenditures of $4,384 million for 2017 were $2,081 million lower than the prior year. The decrease was primarily due to decreased leasehold acquisitions ($2,790 million) and decreased property acquisitions ($676 million), partially offset by increased exploration and development drilling expenditures in the United States ($1,052 million), Trinidad ($106 million) and Other International ($17 million); increased facilities expenditures ($200 million); and increased geological and geophysical expenditures ($20 million). 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 2015 exploration and development expenditures of $4,875 million included $4,007 million in development drilling and facilities, $481 million in property acquisitions, $345 million in exploration and $42 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 20, 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 February 28, 2018 (closed)	15,000	$ 1.063
March 1, 2018 through December 31, 2018	15,000	1.063
2019		
January 1, 2019 through December 31, 2019	20,000	$ 1.075

EOG has entered into additional 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 20, 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 February 28, 2018 (closed)	37,000	$ 3.818
March 1, 2018 through December 31, 2018	37,000	3.818

On March 14, 2017, EOG executed the optional early termination provision granting EOG the right to terminate certain 2017 crude oil price swaps with notional volumes of 30,000 Bbld at a weighted average price of $50.05 per Bbl for the period March 1, 2017 through June 30, 2017. EOG received cash of $4.6 million for the early termination of these contracts, which are included in the table below. Presented below is a comprehensive summary of EOG's crude oil price swap contracts through February 20, 2018, with notional volumes expressed in Bbld and prices expressed in $/Bbl.

Crude Oil Price Swap Contracts

	Volume (Bbld)	Weighted Average Price ($/Bbl)
2017		
January 1, 2017 through February 28, 2017 (closed)	35,000	$ 50.04
March 1, 2017 through June 30, 2017 (closed)	30,000	50.05
2018		
January 2018 (closed)	134,000	$ 60.04
February 1, 2018 through December 31, 2018	134,000	60.04

On March 14, 2017, EOG entered into a crude oil price swap contract for the period March 1, 2017 through June 30, 2017, with notional volumes of 5,000 Bbld at a price of $48.81 per Bbl. This contract offset the remaining 2017 crude oil price swap contract for the same time period with notional volumes of 5,000 Bbld at a price of $50.00 per Bbl. The net cash EOG received for settling these contracts was $0.7 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 20, 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)
2017		
March 1, 2017 through November 30, 2017 (closed)	30,000	$ 3.10
2018		
March 1, 2018 through November 30, 2018	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 20, 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)
2017				
March 1, 2017 through November 30, 2017 (closed)	213,750	$ 3.44	171,000	$ 2.92
2018				
March 1, 2018 through November 30, 2018	120,000	$ 3.38	96,000	$ 2.94

EOG has also entered into natural gas collar contracts, which establish ceiling and floor prices for the sale of notional volumes of natural gas as specified in the collar contracts. The collars require that EOG pay the difference between the ceiling price and the Henry Hub Index Price in the event the Henry Hub Index Price is above the ceiling price. The collars grant EOG the right to receive the difference between the floor price and the Henry Hub Index Price in the event the Henry Hub Index Price is below the floor price. Presented below is a comprehensive summary of EOG's natural gas collar contracts through February 20, 2018, with notional volumes expressed in MMBtud and prices expressed in $/MMbtu.

Natural Gas Collar Contracts

		Weighted Average Price ($/MMbtu)	
	Volume (MMBtud)	Ceiling Price	Floor Price
2017			
March 1, 2017 through November 30, 2017 (closed)	80,000	$ 3.69	$ 3.20

Financing

EOG's debt-to-total capitalization ratio was 28% at December 31, 2017, compared to 33% at December 31, 2016. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

At December 31, 2017 and 2016, respectively, EOG had outstanding $6,390 million and $6,990 million aggregate principal amount of senior notes which had estimated fair values of $6,602 million and $7,190 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 2017, 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 2017 was $803 million, and the amount outstanding at year-end was zero. There were no amounts outstanding under uncommitted credit facilities during 2017. The average borrowings outstanding under the commercial paper program were $84 million during the year 2017. 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, 2017, (in thousands):

Contractual Obligations (1)	**Total**	**2018**	**2019-2020**	**2021-2022**	**2023 & Beyond**
Current and Long-Term Debt	$ 6,390,000	$ 350,000	$ 1,900,000	$ 750,000	$ 3,390,000
Capital Lease	32,220	6,644	14,172	11,404	—
Non-Cancelable Operating Leases	437,597	118,412	118,583	88,039	112,563
Interest Payments on Long-Term Debt and Capital Lease	1,533,624	261,601	382,085	258,139	631,799
Transportation and Storage Service Commitments (2)	3,992,137	883,489	1,403,647	896,607	808,394
Drilling Rig Commitments (3)	245,434	229,372	14,562	1,500	—
Seismic Purchase Obligations	19,596	19,596	—	—	—
Fracturing Services Obligations	688,924	338,825	292,845	34,206	23,048
Other Purchase Obligations	331,620	265,311	39,435	25,968	906
Total Contractual Obligations	**$ 13,671,152**	**$ 2,473,250**	**$ 4,165,329**	**$ 2,065,863**	**$ 4,966,710**

(1) This table does not include the liability for unrecognized tax benefits, repatriation tax liability, 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).

(2) Amounts shown are based on current transportation and storage rates and the foreign currency exchange rates used to convert Canadian dollars and British pounds into United States dollars at December 31, 2017. 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.

(3) 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 2017, EOG was exposed to foreign currency exchange rate risk inherent in its operations in foreign countries, including Trinidad, the United Kingdom, China and Canada. The foreign currency most significant to EOG's operations during 2017 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 2018 will impact the amount of cash generated from EOG's operating activities, which will in turn impact EOG's financial position. As of February 20, 2018, the average 2018 NYMEX crude oil and natural gas prices were $60.75 per barrel and $2.81 per MMBtu, respectively, representing an increase of 19% for crude oil and a decrease of 9% for natural gas from the average NYMEX prices in 2017. See ITEM 1A, Risk Factors.

Including the impact of EOG's 2018 crude oil derivative contracts (exclusive of basis swaps) and based on EOG's tax position, EOG's price sensitivity in 2018 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 $82 million for net income and $106 million for cash flows from operating activities. Including the impact of EOG's 2018 natural gas derivative contracts (exclusive of call options) and based on EOG's tax position and the portion of EOG's anticipated natural gas volumes for 2018 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 $22 million for net income and $29 million for cash flows from operating activities. For information regarding EOG's crude oil and natural gas financial commodity derivative contracts through February 20, 2018, 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 2018 capital expenditures of approximately $5.4 billion to $5.8 billion, excluding acquisitions, 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 2018, both total production and total crude oil production are expected to increase from 2017 levels. In 2018, 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 all 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 charged to expense 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, 2017, West Texas Intermediate crude oil spot prices have fluctuated from approximately $26.19 per barrel to $110.62 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, natural gas prices, actual production or operating costs diverge negatively from EOG's current estimates, impairment charges and downward adjustments to our 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 changes in tax rates. Changes in such assumptions could materially affect the recognized amounts of valuation allowances.

In December 2017, the U.S. enacted the 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's (SEC) staff issued Staff Accounting Bulletin No. 118 (SAB 118), which provides guidance on accounting for the impact of the TCJA. Under SAB 118, an entity would 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 would either (1) recognize provisional amounts to the extent that they are reasonably estimable 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 fiscal year ended December 31, 2017 in accordance with the Income Taxes Topic of the ASC as allowed by SAB 118.

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 of 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, 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," "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, reduce or otherwise control operating and capital costs, generate income or cash flows or pay 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, 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; 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 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 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;

- political conditions and developments around the world (such as 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 cyber security breaches; and
- the other factors described under ITEM 1A, Risk Factors, on pages 14 through 23 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 and 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, 2017. 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, 2017.

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, 2017. 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, 2017. 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, 2017, 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 2018 Annual Meeting of Stockholders to be filed not later than April 30, 2018 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 "Corporate Governance" page under "About EOG" 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 2018 Annual Meeting of Stockholders to be filed not later than April 30, 2018. 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 2018 Annual Meeting of Stockholders to be filed not later than April 30, 2018.

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 its 2018 Annual Meeting of Stockholders, EOG will propose, for stockholder approval, an amendment and restatement of the Employee Stock Purchase Plan (ESPP) to (among other changes) increase the number of shares available for issuance under the ESPP and further extend the term of the ESPP.

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, 2017, 314,935 phantom shares had been issued. The Deferral Plan is currently EOG's only stock plan that has not been approved by EOG's stockholders.

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, 2017.

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	10,612,087	(2)	$	83.89	17,440,825	(3)
Equity Compensation Plans Not Approved by EOG Stockholders	263,403	(4)		N/A	225,065	(5)
Total	**10,875,490**		**$**	**83.89**	**17,665,890**	

(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 1,007,167 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 502,331 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 502,331 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 148,444 and a maximum of 856,218 performance units could be outstanding and (B) accordingly, a minimum of 148,444 and a maximum of 856,218 shares of EOG common stock could be issued upon the vesting of such grants.

(3) Consists of (i) 17,264,788 shares remaining available for issuance under the Amended and Restated 2008 Plan and (ii) 176,037 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 17,264,788 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 17,264,788 (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 7,046,852 (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 263,403 phantom shares issued and outstanding under the Deferral Plan as of December 31, 2017).

(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 2018 Annual Meeting of Stockholders to be filed not later than April 30, 2018.

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 2018 Annual Meeting of Stockholders to be filed not later than April 30, 2018.

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.

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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, 2017. 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, 2017.

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
Chairman of the Board and
Chief Executive Officer

TIMOTHY K. DRIGGERS
Executive Vice President and Chief
Financial Officer

Houston, Texas
February 27, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders 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, 2017 and 2016, 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, 2017, 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, 2017, 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, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, 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, 2017, 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 audit 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 27, 2018

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	2017	2016	2015
Net Operating Revenues and Other			
Crude Oil and Condensate	$ 6,256,396	$ 4,317,341	$ 4,934,562
Natural Gas Liquids	729,561	437,250	407,658
Natural Gas	921,934	742,152	1,061,038
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	19,828	(99,608)	61,924
Gathering, Processing and Marketing	3,298,087	1,966,259	2,253,135
Gains (Losses) on Asset Dispositions, Net	(99,096)	205,835	(8,798)
Other, Net	81,610	81,403	47,909
Total	11,208,320	7,650,632	8,757,428
Operating Expenses			
Lease and Well	1,044,847	927,452	1,182,282
Transportation Costs	740,352	764,106	849,319
Gathering and Processing Costs	148,775	122,901	146,156
Exploration Costs	145,342	124,953	149,494
Dry Hole Costs	4,609	10,657	14,746
Impairments	479,240	620,267	6,613,546
Marketing Costs	3,330,237	2,007,635	2,385,982
Depreciation, Depletion and Amortization	3,409,387	3,553,417	3,313,644
General and Administrative	434,467	394,815	366,594
Taxes Other Than Income	544,662	349,710	421,744
Total	10,281,918	8,875,913	15,443,507
Operating Income (Loss)	926,402	(1,225,281)	(6,686,079)
Other Income (Expense), Net	9,152	(50,543)	1,916
Income (Loss) Before Interest Expense and Income Taxes	935,554	(1,275,824)	(6,684,163)
Interest Expense			
Incurred	301,801	313,341	279,234
Capitalized	(27,429)	(31,660)	(41,841)
Net Interest Expense	274,372	281,681	237,393
Income (Loss) Before Income Taxes	661,182	(1,557,505)	(6,921,556)
Income Tax Benefit	(1,921,397)	(460,819)	(2,397,041)
Net Income (Loss)	**$ 2,582,579**	**$ (1,096,686)**	**$ (4,524,515)**
Net Income (Loss) Per Share			
Basic	$ 4.49	$ (1.98)	$ (8.29)
Diluted	$ 4.46	$ (1.98)	$ (8.29)
Dividends Declared per Common Share	$ 0.670	$ 0.670	$ 0.670
Average Number of Common Shares			
Basic	574,620	553,384	545,697
Diluted	578,693	553,384	545,697
Comprehensive Income (Loss)			
Net Income (Loss)	$ 2,582,579	$ (1,096,686)	$ (4,524,515)
Other Comprehensive Income (Loss)			
Foreign Currency Translation Adjustments	2,799	12,097	(11,517)
Other, Net of Tax	(3,086)	2,231	1,235
Other Comprehensive Income (Loss)	(287)	14,328	(10,282)
Comprehensive Income (Loss)	**$ 2,582,292**	**$ (1,082,358)**	**$ (4,534,797)**

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	2017	2016
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 834,228	$ 1,599,895
Accounts Receivable, Net	1,597,494	1,216,320
Inventories	483,865	350,017
Assets from Price Risk Management Activities	7,699	—
Income Taxes Receivable	113,357	12,305
Other	242,465	206,679
Total	3,279,108	3,385,216
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	52,555,741	49,592,091
Other Property, Plant and Equipment	3,960,759	4,008,564
Total Property, Plant and Equipment	56,516,500	53,600,655
Less: Accumulated Depreciation, Depletion and Amortization	(30,851,463)	(27,893,577)
Total Property, Plant and Equipment, Net	25,665,037	25,707,078
Deferred Income Taxes	17,506	16,140
Other Assets	871,427	190,767
Total Assets	**$ 29,833,078**	**$ 29,299,201**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 1,847,131	$ 1,511,826
Accrued Taxes Payable	148,874	118,411
Dividends Payable	96,410	96,120
Liabilities from Price Risk Management Activities	50,429	61,817
Current Portion of Long-Term Debt	356,235	6,579
Other	226,463	232,538
Total	2,725,542	2,027,291
Long-Term Debt	6,030,836	6,979,779
Other Liabilities	1,275,213	1,282,142
Deferred Income Taxes	3,518,214	5,028,408
Commitments and Contingencies (Note 8)		
Stockholders' Equity		
Common Stock, $0.01 Par, 1,280,000,000 Shares and 640,000,000 Shares Authorized at December 31, 2017 and 2016, respectively, and 578,827,768 Shares and 576,950,272 Shares Issued at December 31, 2017 and 2016, respectively	205,788	205,770
Additional Paid in Capital	5,536,547	5,420,385
Accumulated Other Comprehensive Loss	(19,297)	(19,010)
Retained Earnings	10,593,533	8,398,118
Common Stock Held in Treasury, 350,961 Shares and 250,155 Shares at December 31, 2017 and 2016, respectively	(33,298)	(23,682)
Total Stockholders' Equity	16,283,273	13,981,581
Total Liabilities and Stockholders' Equity	**$ 29,833,078**	**$ 29,299,201**

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, 2014	$ 205,492	$ 2,837,150	$ (23,056)	$ 14,763,098	$ (70,102)	$ 17,712,582
Net Loss	—	—	—	(4,524,515)	—	(4,524,515)
Common Stock Issued Under Stock Plans	5	15,366	—	—	—	15,371
Common Stock Dividends Declared, $0.67 Per Share	—	—	—	(367,767)	—	(367,767)
Other Comprehensive Loss	—	—	(10,282)	—	—	(10,282)
Change in Treasury Stock - Stock Compensation Plans, Net	—	(41,342)	—	—	(129)	(41,471)
Excess Tax Benefit from Stock-Based Compensation	—	26,058	—	—	—	26,058
Restricted Stock and Restricted Stock Units, Net	5	(44,339)	—	—	44,334	—
Stock-Based Compensation Expenses	—	130,577	—	—	—	130,577
Treasury Stock Issued as Compensation	—	(9)	—	—	2,491	2,482
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 Loss	—	—	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**

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	2017	2016	2015
Cash Flows from Operating Activities			
Reconciliation of Net Income (Loss) to Net Cash Provided by Operating Activities:			
Net Income (Loss)	$ 2,582,579	$ (1,096,686)	$ (4,524,515)
Items Not Requiring (Providing) Cash			
Depreciation, Depletion and Amortization	3,409,387	3,553,417	3,313,644
Impairments	479,240	620,267	6,613,546
Stock-Based Compensation Expenses	133,849	128,090	130,577
Deferred Income Taxes	(1,473,872)	(515,206)	(2,482,307)
(Gains) Losses on Asset Dispositions, Net	99,096	(205,835)	8,798
Other, Net	6,546	61,690	11,896
Dry Hole Costs	4,609	10,657	14,746
Mark-to-Market Commodity Derivative Contracts			
Total (Gains) Losses	(19,828)	99,608	(61,924)
Net Cash Received from (Payments for) Settlements of Commodity Derivative Contracts	7,438	(22,219)	730,114
Excess Tax Benefits from Stock-Based Compensation	—	(29,357)	(26,058)
Other, Net	1,204	10,971	12,532
Changes in Components of Working Capital and Other Assets and Liabilities			
Accounts Receivable	(392,131)	(232,799)	641,412
Inventories	(174,548)	170,694	58,450
Accounts Payable	324,192	(74,048)	(1,409,197)
Accrued Taxes Payable	(63,937)	92,782	11,798
Other Assets	(658,609)	(40,636)	118,143
Other Liabilities	(89,871)	(16,225)	(66,257)
Changes in Components of Working Capital Associated with Investing and Financing Activities	89,992	(156,102)	499,767
Net Cash Provided by Operating Activities	4,265,336	2,359,063	3,595,165
Investing Cash Flows			
Additions to Oil and Gas Properties	(3,950,918)	(2,489,756)	(4,725,150)
Additions to Other Property, Plant and Equipment	(173,324)	(93,039)	(288,013)
Proceeds from Sales of Assets	226,768	1,119,215	192,807
Net Cash Received from Yates Transaction	—	54,534	—
Changes in Components of Working Capital Associated with Investing Activities	(89,935)	156,102	(499,900)
Net Cash Used in Investing Activities	(3,987,409)	(1,252,944)	(5,320,256)
Financing Cash Flows			
Net Commercial Paper (Repayments) Borrowings	—	(259,718)	259,718
Long-Term Debt Borrowings	—	991,097	990,225
Long-Term Debt Repayments	(600,000)	(563,829)	(500,000)
Dividends Paid	(386,531)	(372,845)	(367,005)
Excess Tax Benefits from Stock-Based Compensation	—	29,357	26,058
Treasury Stock Purchased	(63,408)	(82,125)	(48,791)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	20,840	23,296	22,690
Debt Issuance Costs	—	(1,602)	(5,951)
Repayment of Capital Lease Obligation	(6,555)	(6,353)	(6,156)
Other, Net	(57)	—	133
Net Cash (Used in) Provided by Financing Activities	(1,035,711)	(242,722)	370,921
Effect of Exchange Rate Changes on Cash	(7,883)	17,992	(14,537)
Increase (Decrease) in Cash and Cash Equivalents	(765,667)	881,389	(1,368,707)
Cash and Cash Equivalents at Beginning of Year	1,599,895	718,506	2,087,213
Cash and Cash Equivalents at End of Year	**$ 834,228**	**$ 1,599,895**	**$ 718,506**

The accompanying notes are an integral part of these 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 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 (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 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 future crude oil and natural gas prices, operating costs, 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. If applicable, EOG utilizes accepted bids 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.

Arrangements for sales of crude oil and condensate, natural gas liquids (NGLs) and natural gas are evidenced by signed contracts with determinable market prices, and revenues are recorded when production is delivered. A significant majority of these products are sold to purchasers who have investment-grade credit ratings and material credit losses have been rare. Revenues are recorded on the entitlement method based on EOG's percentage ownership of current production. Each working interest owner in a well generally has the right to a specific percentage of production, although actual production sold on that owner's behalf may differ from that owner's ownership percentage. Under entitlement accounting, a receivable is recorded when underproduction occurs and a payable is recorded when overproduction occurs. Gathering, processing and marketing revenues represent sales of third-party crude oil and condensate, NGLs and natural gas, as well as gathering fees associated with gathering third-party natural gas and revenues from sales of EOG-owned sand.

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, 2017, 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 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's (SEC) staff issued Staff Accounting Bulletin No. 118 (SAB 118), which provides guidance on accounting for the impact of the TCJA. Under SAB 118, an entity would 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 would either (1) recognize provisional amounts to the extent that they are reasonably estimable 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 fiscal year ended December 31, 2017 in accordance with the Income Taxes Topic of the ASC as allowed by SAB 118. 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, for which the functional currency is 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 Income (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 (loss) in the current period. See Note 4.

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 2017, the FASB issued Accounting Standards Update (ASU) 2017-05, "Other Income - Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20) - Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets" (ASU 2017-05). ASU 2017-05 clarifies the scope and application of ASC 610-20 to the sale or transfer of nonfinancial assets and, in substance, nonfinancial assets to noncustomers, including partial sales. ASU 2017-05 is effective for interim and annual periods beginning after December 15, 2017. EOG will adopt ASU 2017-05 in connection with the adoption of "Revenue From Contracts With Customers" (ASU 2014-09) effective January 1, 2018.

In January 2017, the FASB issued ASU 2017-01 "Business Combinations (Topic 805): Clarifying the Definition of a Business" (ASU 2017-01), which clarifies the definition of a business to provide guidance in evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 provides a screen to determine when a set of assets is not a business, requiring that when substantially all fair value of gross assets acquired (or disposed of) is concentrated in a single identifiable asset or group of similar identifiable assets, the set of assets is not a business. A framework is provided to assist in evaluating whether both an input and a substantive process are present for the set to be a business. ASU 2017-01 is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. No disclosures are required at transition. The new standard may result in more transactions being accounted for as acquisitions (and dispositions) of assets rather than businesses. EOG will adopt ASU 2017-01 on a prospective basis effective January 1, 2018.

In August 2016, the FASB issued ASU 2016-15, “Statement of Cash Flows (Topic 230) - Classification of Certain Cash Receipts and Cash Payments” (ASU 2016-15). ASU 2016-15 reduces existing diversity in practice by providing guidance on the classification of eight specific cash receipts and cash payments transactions in the statement of cash flows. The new standard is effective for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. EOG will adopt ASU 2016-15 on a retrospective basis on January 1, 2018. There will be no impact to the presentation of comparable periods upon adoption.

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 virtually all 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." ASU 2016-02 is effective for interim and annual periods beginning after December 31, 2018 and early application is permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented in the financial statements using a modified retrospective approach. EOG is continuing its assessment of ASU 2016-02 and has further developed its project plan, evaluated certain operational and corporate processes and selected certain contracts for additional review.

In May 2014, the FASB issued ASU 2014-09, which will 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. ASU 2014-09 will supersede most current guidance related to revenue recognition when it becomes effective. The new standard also will require expanded disclosures regarding the nature, amount, timing and certainty of revenue and cash flows from contracts with customers. ASU 2014-09 is effective for interim and annual reporting periods beginning after December 15, 2017. The new standard permits adoption through the use of either the full retrospective approach or a modified retrospective approach. In May 2016, the FASB issued ASU 2016-11, which rescinds certain SEC guidance in the related ASC, including guidance related to the use of the "entitlements" method of revenue recognition used by EOG. EOG will adopt ASU 2014-09 utilizing the modified retrospective approach effective January 1, 2018. Upon adoption of ASU 2014-09, EOG expects to prospectively present natural gas processing fees for certain processing and marketing agreements as Gathering and Processing Costs, instead of a deduction to Revenues within its Consolidated Statements of Income (Loss) and Comprehensive Income (Loss). EOG does not expect a material impact to operating income, net income or cash flows upon changes to the presentation of natural gas processing fees. Also, EOG does not expect a material impact to the financial statements upon elimination of the entitlements method and other adoption requirements. Upon adoption, EOG will also include additional disclosures as required by ASU 2014-09.

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 December 31, 2016 balance sheet to reclassify $169 million of current deferred income tax assets as noncurrent.

Effective January 1, 2017, EOG adopted the provisions of ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting" (ASU 2016-09), which amends certain aspects of accounting for share-based payment arrangements. ASU 2016-09 revises or provides alternative accounting for the tax impacts of share-based payment arrangements, forfeitures and minimum statutory tax withholdings and prescribes certain disclosures to be made in the period the new standard is adopted. There was no impact to retained earnings with respect to excess tax benefits. 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 income tax provision was $32 million for the year ended December 31, 2017. The treatment of forfeitures did not change as EOG elected to continue the current process of estimating the number of forfeitures. As such, this had no cumulative effect on retained earnings. EOG elected to present changes to the statements of cash flows on a prospective transition method.

2. Long-Term Debt

Long-Term Debt at December 31, 2017 and 2016 consisted of the following (in thousands):

	2017	2016
5.875% Senior Notes due 2017	$ —	$ 600,000
6.875% Senior Notes due 2018	350,000	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	6,390,000	6,990,000
Capital Lease Obligation	32,155	38,710
Less: Current Portion of Long-Term Debt	356,235	6,579
Unamortized Debt Discount	30,564	36,915
Debt Issuance Costs	4,520	5,437
Total Long-Term Debt	**$ 6,030,836**	**$ 6,979,779**

At December 31, 2017, the aggregate annual maturities of long-term debt (excluding capital lease obligations) were $350 million in 2018, $900 million in 2019, $1 billion in 2020, $750 million in 2021 and zero in 2022. At December 31, 2017 and 2016, EOG had no outstanding short-term borrowings under the commercial paper program and no outstanding borrowings under uncommitted credit facilities.

During 2017 and 2016, EOG utilized commercial paper bearing market interest rates, for various corporate financing purposes. EOG had no outstanding commercial paper borrowings at December 31, 2017. The average borrowings outstanding under the commercial paper program were $84 million and $130 million during the years ended December 31, 2017 and 2016, respectively. The weighted average interest rates for commercial paper borrowings were 1.44% and 0.76% for the years 2017 and 2016, respectively.

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

On February 1, 2016, EOG repaid upon maturity the $400 million aggregate principal amount of its 2.500% Senior Notes due 2016.

On January 14, 2016, EOG closed its sale of $750 million aggregate principal amount of its 4.15% Senior Notes due 2026 and $250 million aggregate principal amount of its 5.10% Senior Notes due 2036 (collectively, the Notes). Interest on the Notes is payable semi-annually in arrears on January 15 and July 15 of each year, beginning on July 15, 2016. Net proceeds from the Notes offering totaled approximately $991 million and were used to repay EOG's 2.500% Senior Notes due 2016 and for general corporate purposes, including repayment of outstanding commercial paper borrowings and funding of future capital expenditures.

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, 2017, EOG was in compliance with this financial covenant. At December 31, 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, would have been 2.56% and 4.50%, 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, 2017, 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 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.

EOG declared and paid quarterly cash dividends of $0.1675 per share in 2017, 2016 and 2015. On February 27, 2018, EOG's Board increased the quarterly cash dividend on the common stock by 10% from the current $0.1675 per share to $0.1850 per share, effective beginning with the dividend to be paid on April 30, 2018, to stockholders of record as of April 16, 2018.

The following summarizes Common Stock activity for each of the years ended December 31, 2015, 2016 and 2017 (in thousands):

	Common Shares		
	Issued	**Treasury**	**Outstanding**
Balance at December 31, 2014	549,028	(733)	548,295
Common Stock Issued Under Stock-Based Compensation Plans	1,019	—	1,019
Treasury Stock Purchased (1)	—	(581)	(581)
Common Stock Issued Under Employee Stock Purchase Plan	104	121	225
Treasury Stock Issued Under Stock-Based Compensation Plans	—	901	901
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

(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, 2017, 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, 2017 and 2016 consisted of the following (in thousands):

	Foreign Currency Translation Adjustment	Other	Total
December 31, 2015	**$ (31,538)**	**$ (1,800)**	**$ (33,338)**
Other comprehensive loss before reclassifications	12,097	2,901	14,998
Tax effects	—	(670)	(670)
Other comprehensive income (loss)	12,097	2,231	14,328
December 31, 2016	**(19,441)**	**431**	**(19,010)**
Other comprehensive income before reclassifications	2,799	(3,728)	(929)
Tax effects	—	642	642
Other comprehensive income	2,799	(3,086)	(287)
December 31, 2017	**$ (16,642)**	**$ (2,655)**	**$ (19,297)**

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 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). Other income, net, for 2015 included equity income from investments in ammonia plants in Trinidad ($9 million), a downward adjustment to deferred compensation expense ($6 million), interest income ($3 million) and net foreign currency transaction losses ($(17) million).

6. Income Taxes

As previously discussed, the U.S. enacted the TCJA in December 2017. Under the Income Taxes Topic of the ASC, the effects of new legislation are recognized upon enactment. Accordingly, recognition of the tax effects of the TCJA is required in the consolidated financial statements for the fiscal year ended December 31, 2017. Shortly after enactment of the TCJA, the SEC staff issued SAB 118 addressing the application of U.S. GAAP in situations when the registrant does not have the necessary information available or analyzed in reasonable detail to complete the accounting for certain income tax effects of the TCJA. Under SAB 118, an entity would 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 would either (1) recognize provisional amounts to the extent that they are reasonably estimable 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 fiscal year ended December 31, 2017 in accordance with the Income Taxes Topic of the ASC as allowed by SAB 118.

EOG has not completed the determination of the accounting impact of the TCJA on its tax accruals, but believes that it has made reasonable estimates of the effects of the TCJA with the information currently available. Following is a description of each of the principal changes enacted by the TCJA affecting EOG, the impact of such change on EOG's results of operations, cash flows and consolidated financial statements, and, to the extent that the amount is provisional, an explanation of the reasons the initial accounting is incomplete.

The TCJA reduces the corporate income tax rate from 35% to 21% effective January 1, 2018. As provided in the Income Taxes Topic of the ASC, EOG remeasured its U.S. deferred tax assets and liabilities to reflect the effects of the tax rate change. EOG recorded a provisional reduction in the 2017 income tax provision in the amount of approximately $2.2 billion, most of which related to the decrease in the tax rate. However, this amount may change based on further analysis of tax elections available to EOG, as well as any additional clarification provided by the Internal Revenue Service (IRS).

In addition, the TCJA repeals the corporate alternative minimum tax (AMT) for tax years beginning January 1, 2018, and provides that existing AMT credit carryovers from 2017 and prior years can be applied against regular tax liabilities beginning in 2018. To the extent that AMT credit carryovers are not used to offset regular tax liabilities, these credits are refundable over four years beginning in 2018. EOG estimates that its AMT credits being carried over to 2018 will total approximately $798 million (inclusive of the expected IRS settlement discussed below). The exact amount of the AMT credit carryover cannot be currently determined, however, due to a federal budgetary provision known as "sequestration," in which a portion of certain refunds are permanently withheld by the government. The sequestration rate, currently at 6.6%, is revised each year, and EOG cannot precisely estimate the rate that might be applicable during the next four years. In addition, the AMT credits may be applied against future regular tax liabilities, which would reduce the amount of AMT credit refunds, as well as the corresponding amount of the sequestration charge. In 2017, EOG recorded an accrual in the amount of $42 million related to the possible sequestration of refundable tax credits.

The TCJA further provides for a tax on the deemed repatriation of accumulated foreign earnings for the year ended December 31, 2017. The deemed repatriation tax is based on the amount of post-1986 earnings and profits of EOG's foreign subsidiaries and the amount of foreign cash and cash equivalents. At the election of the taxpayer, the deemed repatriation tax liability can be paid over eight years beginning with 2017 on an interest-free basis. EOG expects that it will pay its estimated deemed repatriation tax of approximately $179 million under this election. EOG cannot finalize the amount of the repatriation tax due to the possible impact of certain tax elections that require further analysis, the completion of its foreign earnings and profits study, and further clarification provided by the IRS.

Also, the TCJA makes fundamental changes to the taxation of multinational companies, including a shift beginning in 2018 to a so-called territorial system of taxation that features a participation exemption regime. EOG believes that under this new system it will not incur any significant amount of U.S. federal income taxes with respect to its foreign operating earnings. Prior to this change being enacted, EOG had accrued U.S. federal deferred income taxes in the amount of $260 million related to its accumulated foreign earnings. Due to this tax law change, EOG reversed this accrual in 2017, resulting in a provisional reduction in its 2017 federal tax provision of approximately $43 million, net of the earnings impact of the repatriation tax described above. However, although future foreign dividends should be exempt from U.S. federal income taxes, EOG must still account for the tax consequences of outside basis differences in its investments in non-U.S. subsidiaries. While EOG believes that no U.S. federal deferred income tax liabilities should be recorded for such outside basis differences, future IRS pronouncements may require that EOG make certain adjustments to the tax basis of its non-U.S. subsidiaries, resulting in EOG having to record additional U.S. federal deferred income tax liabilities.

The TCJA also provides for 100% bonus depreciation on tangible personal property acquired and placed in service after September 27, 2017, and before December 31, 2023. It also provides for a phase down of bonus depreciation for the years 2023 through 2026. The impact of this provision will depend on EOG's future domestic capital spending, which cannot be precisely determined at this time, but it is expected to have a favorable effect on EOG's cash tax position prospectively.

In addition, the TCJA includes certain limitations on the federal tax deductibility of interest expense, net operating losses and executive compensation. Although EOG does not currently believe that these changes will have a significant impact on EOG's tax provision in the foreseeable future, additional analysis is required.

The IRS has recently issued several pronouncements addressing certain aspects of the TCJA and EOG expects that the IRS will continue providing clarifying guidance, some of which could have a significant impact on EOG's reported amounts.

The principal components of EOG's net deferred income tax liabilities at December 31, 2017 and 2016 were as follows (in thousands):

	2017 (1)	2016 (1) (2)
Noncurrent Deferred Income Tax Assets (Liabilities)		
Foreign Oil and Gas Exploration and Development Costs Deducted for Tax Under Book Depreciation, Depletion and Amortization	$ (40,851)	$ (39,852)
Foreign Net Operating Loss	423,258	352,150
Foreign Valuation Allowances	(365,379)	(296,596)
Foreign Other	478	438
Total Net Noncurrent Deferred Income Tax Assets	**$ 17,506**	**$ 16,140**
Noncurrent Deferred Income Tax (Assets) Liabilities		
Oil and Gas Exploration and Development Costs Deducted for Tax Over Book Depreciation, Depletion and Amortization	$ 3,894,739	$ 5,899,533
Commodity Hedging Contracts	(12,008)	(22,206)
Deferred Compensation Plans	(35,832)	(43,984)
Accrued Expenses and Liabilities	12,094	(13,754)
Net Operating Loss - Federal	(69,262)	—
Non-Producing Leasehold Costs	(47,981)	(64,898)
Seismic Costs Capitalized for Tax	(109,423)	(161,920)
Equity Awards	(92,696)	(139,787)
Capitalized Interest	51,345	86,504
Alternative Minimum Tax Credit Carryforward (3)	(77,114)	(757,631)
Undistributed Foreign Earnings (4)	19,684	280,099
Other	(15,332)	(33,548)
Total Net Noncurrent Deferred Income Tax Liabilities	**$ 3,518,214**	**$ 5,028,408**
Total Net Deferred Income Tax Liabilities	**$ 3,500,708**	**$ 5,012,268**

(1) United States federal deferred tax assets and liabilities tax effected at 21% and 35% for 2017 and 2016, respectively.
(2) As described in Note 1, ASU 2015-17 eliminated the requirement to separate deferred tax assets and liabilities into current and noncurrent amounts.
(3) Pursuant to the TCJA, $721 million of federal AMT credit carryforwards are expected to be refundable over four years and are presented as noncurrent tax receivables in Other Assets on the Consolidated Balance Sheet at December 31, 2017.
(4) Undistributed foreign earnings have been deemed repatriated in 2017 in accordance with the TCJA. A portion of the associated federal taxes are now reflected as a noncurrent tax payable as a result of the eight year installment election.

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

	2017	2016	2015
United States	$ 621,610	$ (1,520,573)	$ (6,840,119)
Foreign	39,572	(36,932)	(81,437)
Total	**$ 661,182**	**$ (1,557,505)**	**$ (6,921,556)**

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

	2017	2016	2015
Current:			
Federal	$ 33,058	$ 11,567	$ 21,719
State	(2,502)	(8,369)	9,404
Foreign	35,323	51,189	54,143
Total	65,879	54,387	85,266
Deferred:			
Federal	(1,504,288)	(532,979)	(2,362,926)
State	26,942	4,876	(127,444)
Foreign	3,474	12,897	8,063
Total	(1,473,872)	(515,206)	(2,482,307)
Other Non-Current:			
Federal (1)	(513,404)	—	—
Income Tax Benefit	**$ (1,921,397)**	**$ (460,819)**	**$ (2,397,041)**

(1) As described previously, under the TCJA, a deemed repatriation tax is to be paid over eight years beginning with respect to taxable year 2017. In addition, EOG expects to receive refunds of AMT credits over a four-year period beginning with respect to taxable year 2018. Other Non-Current includes the portion of these two items that relates to years after 2017.

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

	2017	2016	2015
Statutory Federal Income Tax Rate	35.00 %	35.00 %	35.00 %
State Income Tax, Net of Federal Benefit	3.38	0.15	1.11
Income Tax Provision Related to Foreign Operations	(0.30)	(1.23)	(1.31)
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 (1)	(328.10)	—	—
Share-Based Compensation (2)	(4.63)	—	—
Other	(0.03)	(0.62)	(0.17)
Effective Income Tax Rate	**(290.60)%**	**29.59%**	**34.63%**

(1) Includes impact of federal tax rate reduction ((327.8)%), federal repatriation tax ((6.6)%), sequestration (6.4%) and other tax reform impacts ((0.1)%).
(2) As described in Note 1, ASU 2016-09, adopted by EOG in 2017, provides that share-based compensation tax benefits and deficiencies are recognized in the income tax provision.

The effective tax rate of (291)% in 2017 was lower than the prior year rate of 30% primarily as a result of the remeasurement of the net U.S. deferred income tax liability at 21% due to the enactment of the TCJA previously discussed.

Deferred tax assets are recorded for certain tax benefits, including tax net operating losses (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.

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

	2017	2016	2015
Beginning Balance	$ 383,221	$ 506,127	$ 463,018
Increase [1]	67,333	37,221	146,602
Decrease [2]	(13,687)	(12,667)	(4,315)
Other [3]	29,554	(147,460)	(99,178)
Ending Balance	**$ 466,421**	**$ 383,221**	**$ 506,127**

(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/foreign exchange rate variances and the effect of statutory income tax rate changes.

As of December 31, 2017, EOG had state income tax NOLs being carried forward of approximately $1.7 billion, which, if unused, expire between 2018 and 2036. During 2017, EOG's United Kingdom subsidiary incurred a tax NOL of approximately $72 million which, along with prior years' NOLs of $857 million, will be carried forward indefinitely. EOG also has United States federal and Canadian NOLs of $335 million and $158 million, respectively, with varying carryforward periods. EOG's remaining AMT credits total $798 million, resulting from AMT paid with respect to prior years and an increase of $41 million in 2017. As described above, these NOLs and credits, as well as other less significant future income 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.

As further described above, significant changes were made by the TCJA to the corporate AMT that are favorable to EOG, including the refunding of AMT credit carryovers. Due to these legislative changes, EOG intends to settle certain uncertain tax positions related to AMT credits for taxable years 2011 through 2015, resulting in a decrease of uncertain tax positions of $40 million. The amount of unrecognized tax benefits at December 31, 2017, was $39 million, resulting from the tax treatment of its research and experimental expenditures related to certain innovations in its horizontal drilling and completion projects, which is not expected to have an earnings impact. EOG records interest and penalties related to unrecognized tax benefits to its income tax provision. EOG does not anticipate that the amount of the unrecognized tax benefits will increase during the next twelve months. EOG and its subsidiaries file income tax returns and are subject to tax audits in the United States and various state, local and foreign jurisdictions. EOG's earliest open tax years in its principal jurisdictions are as follows: United States federal (2011), Canada (2014), United Kingdom (2016), Trinidad (2011) and China (2008).

EOG's foreign subsidiaries' undistributed earnings are no longer considered to be permanently reinvested outside the U.S. and, accordingly, EOG has cumulatively recorded $20 million of foreign and state deferred income taxes as of December 31, 2017.

7. Employee Benefit Plans

Stock-Based Compensation

During 2017, 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, 2017, 2016 and 2015 was as follows (in millions):

	2017	2016	2015
Lease and Well	$ 41	$ 38	$ 44
Gathering and Processing Costs	1	1	1
Exploration Costs	23	21	26
General and Administrative	69	68	60
Total	$ 134	$ 128	$ 131

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, 2017, approximately 17.3 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 2017, 2016 and 2015, 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 was $32 million for the twelve months ended December 31, 2017. 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 and $26 million for 2016 and 2015, respectively, related to the exercise of stock options/SARs and the release of restricted stock, restricted stock units, performance stock and performance units.

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 $56 million, $57 million and $56 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants for the years ended December 31, 2017, 2016 and 2015 were as follows:

	Stock Options/SARs			ESPP		
	2017	2016	2015	2017	2016	2015
Weighted Average Fair Value of Grants	$ 23.95	$ 25.78	$ 21.88	$ 22.20	$ 19.21	$ 21.21
Expected Volatility	28.28%	31.54%	38.03%	27.12%	36.55%	32.08%
Risk-Free Interest Rate	1.52%	0.78%	0.83%	0.88%	0.44%	0.12%
Dividend Yield	0.75%	0.76%	0.85%	0.71%	0.82%	0.73%
Expected Life	5.1 years	5.4 years	5.3 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, 2017, 2016 and 2015 (stock options and SARs in thousands):

	2017		2016		2015	
	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	9,850	$ 75.53	10,744	$ 67.98	10,493	$ 64.96
Granted	2,274	96.27	1,855	94.82	2,037	69.99
Exercised [(1)]	(2,574)	61.12	(2,376)	54.56	(1,518)	47.64
Forfeited	(447)	93.84	(373)	87.38	(268)	80.31
Outstanding at December 31	9,103	83.89	9,850	75.53	10,744	67.98
Stock Options/SARs Exercisable at December 31	4,510	75.76	5,613	66.48	5,993	57.96

(1) The total intrinsic value of stock options/SARs exercised during the years 2017, 2016 and 2015 was $95 million, $84 million and $60 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, 2017, there were 8.7 million stock options/SARs vested or expected to vest with a weighted average grant price of $83.56 per share, an intrinsic value of $213 million and a weighted average remaining contractual life of 4.3 years.

The following table summarizes certain information for the stock options and SARs outstanding and exercisable at December 31, 2017 (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)]
$ 34.00 to $ 59.99	1,472	1	$ 49.63		1,472	1	$ 49.63	
60.00 to 84.99	2,392	4	75.67		1,623	3	78.51	
85.00 to 95.99	1,684	6	94.82		421	5	94.73	
96.00 to 99.99	2,239	7	96.32		21	3	98.06	
100.00 to 116.99	1,316	4	102.03		973	3	102.03	
	9,103	4	83.89	$ 218,696	4,510	3	75.76	$ 145,024

(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, 2017, unrecognized compensation expense related to non-vested stock option and SAR grants totaled $98 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.4 years.

At December 31, 2017, approximately 176,000 shares of Common Stock remained available for issuance under the ESPP. At its 2018 Annual Meeting of Stockholders, EOG will propose, for stockholder approval, an amendment and restatement of the ESPP to (among other changes) increase the number of shares available for issuance under the ESPP. The following table summarizes ESPP activities for the years ended December 31, 2017, 2016 and 2015 (in thousands, except number of participants):

	2017	2016	2015
Approximate Number of Participants	1,870	1,746	1,963
Shares Purchased	180	212	225
Aggregate Purchase Price	$ 13,997	$ 13,787	$ 15,045

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 $68 million, $60 million and $69 million for the years ended December 31, 2017, 2016 and 2015, respectively.

The following table sets forth the restricted stock and restricted stock unit transactions for the years ended December 31, 2017, 2016 and 2015 (shares and units in thousands):

	2017		2016		2015	
	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	3,962	$ 79.63	4,908	$ 70.35	5,394	$ 64.39
Granted	1,095	97.34	853	88.01	1,044	77.94
Released [1]	(929)	61.51	(1,465)	53.95	(1,331)	51.52
Forfeited	(223)	85.45	(334)	77.29	(199)	74.56
Outstanding at December 31 [2]	3,905	88.57	3,962	79.63	4,908	70.35

(1) The total intrinsic value of restricted stock and restricted stock units released during the years ended December 31, 2017, 2016 and 2015 was $91 million, $124 million and $109 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, 2017, 2016 and 2015 was approximately $421 million, $401 million and $347 million, respectively.

At December 31, 2017, unrecognized compensation expense related to restricted stock and restricted stock units totaled $173 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 2.4 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 $10 million, $11 million and $5 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Weighted average fair values and valuation assumptions used to value Performance Awards during the years ended December 31, 2017, 2016 and 2015 were as follows:

	2017	2016	2015
Weighted Average Fair Value of Grants	$ 113.81	$ 119.10	$ 80.64
Expected Volatility	32.19%	32.48%	29.35%
Risk-Free Interest Rate	1.60%	1.15%	1.07%

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 based on a 3.27 year term-matched zero-coupon risk-free interest rate derived from the Treasury Constant Maturities yield curve on the grant date.

The following table sets forth the Performance Awards transactions for the years ended December 31, 2017, 2016 and 2015:

	2017		2016		2015	
	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	545,290	$ 80.92	405,000	$ 74.93	333,195	$ 76.11
Granted	78,527	96.29	131,750	100.95	71,805	69.43
Granted for Performance Multiple (1)	118,834	84.43	142,556	56.21	—	—
Released (2)	(240,320)	66.69	(134,016)	56.21	—	—
Forfeited	—	—	—	—	—	—
Outstanding at December 31 (3)	502,331 (4)	90.96	545,290	80.92	405,000	74.93

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

(2) The total intrinsic value of Performance Awards released during the years ended December 31, 2017, 2016 and 2015 was approximately $24 million, $10 million and $0, respectively.

(3) The total intrinsic value of Performance Awards outstanding at December 31, 2017, 2016 and 2015 was approximately $54 million, $55 million and $29 million, respectively.

(4) Upon the application of the relevant performance multiple at the completion of each of the remaining Performance Periods, a minimum of 148,444 and a maximum of 856,218 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, 2017, unrecognized compensation expense related to Performance Awards totaled $8.3 million. Such unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.0 years.

Upon completion of the performance period for the Performance Awards granted in 2014, a performance multiple of 200% was applied to the 2014 grants resulting in an additional grant of 71,805 Performance Awards in February 2018.

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 $37 million, $34 million and $36 million for 2017, 2016 and 2015, respectively.

In addition, EOG's Trinidadian subsidiary maintains a contributory defined benefit pension plan and a matched savings plan. EOG's United Kingdom subsidiary maintains a pension plan which includes 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 and United Kingdom subsidiaries. EOG's combined contributions to these plans were $1 million, $1 million and $1 million for 2017, 2016 and 2015, respectively.

For the Trinidadian defined benefit pension plan, the benefit obligation, fair value of plan assets and accrued benefit cost totaled $10 million, $8 million and $0.2 million, respectively, at December 31, 2017, and $8 million, $7 million and $0.3 million, respectively, at December 31, 2016. In connection with the divestiture of substantially all of its Canadian assets in the fourth quarter of 2014, EOG has terminated the Canadian non-contributory defined benefit pension plan.

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, 2017 and 2016, respectively, EOG had standby letters of credit and guarantees outstanding totaling approximately $174 million and $226 million, primarily representing guarantees of payment or performance obligations on behalf of subsidiaries. As of February 20, 2018, EOG had received no demands for payment under these guarantees.

Minimum Commitments. At December 31, 2017, 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 and British pounds into United States dollars at December 31, 2017, were as follows (in thousands):

	Total Minimum Commitments
2018	$ 1,855,005
2019	1,068,994
2020	800,078
2021	567,840
2022	478,480
2023 and beyond	944,911
	$ 5,715,308

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 $200 million, $204 million, and $229 million for 2017, 2016 and 2015, 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, 2017, 2016 and 2015 (in thousands, except per share data):

	2017	2016	2015
Numerator for Basic and Diluted Earnings per Share -			
Net Income (Loss)	$ 2,582,579	$ (1,096,686)	$ (4,524,515)
Denominator for Basic Earnings per Share -			
Weighted Average Shares	574,620	553,384	545,697
Potential Dilutive Common Shares -			
Stock Options/SARs	1,466	—	—
Restricted Stock/Units and Performance Units/Stock	2,607	—	—
Denominator for Diluted Earnings per Share -			
Adjusted Diluted Weighted Average Shares	578,693	553,384	545,697
Net Income (Loss) Per Share			
Basic	$ 4.49	$ (1.98)	$ (8.29)
Diluted	$ 4.46	$ (1.98)	$ (8.29)

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 2.6 million, 10.3 million and 10.2 million for the years ended December 31, 2017, 2016 and 2015, 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, 2017, 2016 and 2015 (in thousands):

	2017	2016	2015
Interest, Net of Capitalized Interest	$ 275,305	$ 252,030	$ 222,088
Income Taxes, Net of Refunds Received	$ 188,946	$ (39,293)	$ 41,108

EOG's accrued capital expenditures at December 31, 2017, 2016 and 2015 were $475 million, $388 million and $416 million, respectively.

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, the United Kingdom and China. 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, 2017, 2016 and 2015 (in thousands):

	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 (Losses) on Mark-to-Market Commodity Derivative Contracts	19,828	—	—	19,828
Gathering, Processing and Marketing	3,298,098	(11)	—	3,298,087
Gains (Losses) on Asset Dispositions, Net	(98,233)	(8)	(855)	(99,096)
Other, Net	81,610	59	(59)	81,610
Net Operating Revenues and Other [2]	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

	United States	Trinidad	Other International (1)	Total
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
Net Operating Revenues and Other (3)	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 (4)	27,746,851	889,253	663,097	29,299,201
2015				
Crude Oil and Condensate	$ 4,917,731	$ 13,122	$ 3,709	$ 4,934,562
Natural Gas Liquids	407,570	—	88	407,658
Natural Gas	637,452	368,639	54,947	1,061,038
Gains on Mark-to-Market Commodity Derivative Contracts	61,924	—	—	61,924
Gathering, Processing and Marketing	2,254,477	(1,342)	—	2,253,135
Gains (Losses) on Asset Dispositions, Net	(12,176)	393	2,985	(8,798)
Other, Net	47,464	(3)	448	47,909
Net Operating Revenues and Other (5)	8,314,442	380,809	62,177	8,757,428
Depreciation, Depletion and Amortization	3,139,863	154,853	18,928	3,313,644
Operating Income (Loss)	(6,566,282)	175,658	(295,455)	(6,686,079)
Interest Income	1,913	389	1,167	3,469
Other Income (Expense)	6,461	8,780	(16,794)	(1,553)
Net Interest Expense	274,606	1,400	(38,613)	237,393
Income (Loss) Before Income Taxes	(6,832,514)	183,427	(272,469)	(6,921,556)
Income Tax Provision (Benefit)	(2,463,213)	63,502	2,670	(2,397,041)
Additions to Oil and Gas Properties, Excluding Dry Hole Costs	4,495,730	102,358	112,316	4,710,404
Total Property, Plant and Equipment, Net	23,593,995	350,766	265,960	24,210,721
Total Assets (6)	25,211,572	886,826	736,510	26,834,908

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

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

(3) 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 Net Operating Revenues and Other in the United States segment.

(4) 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.

(5) EOG had sales activity with two significant purchasers in 2015, one totaling $1.7 billion and the other totaling $1.4 billion of consolidated Net Operating Revenues and Other in the United States segment.

(6) EOG made a reclassification of $136 million from deferred tax liabilities to deferred tax assets for the year ended December 31, 2015, 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 2017, 2016 and 2015, 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 2017, 2016 and 2015, EOG recognized net gains (losses) on the mark-to-market of financial commodity derivative contracts of $20 million, $(100) million and $62 million, respectively, which included cash received from (payments for) settlements of crude oil and natural gas derivative contracts of $7 million, $(22) million and $730 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, 2017. 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 2018 (closed)	15,000	$ 1.063
February 1, 2018 through December 31, 2018	15,000	1.063
2019		
January 1, 2019 through December 31, 2019	20,000	$ 1.075

EOG has entered into additional 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, 2017. 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 2018 (closed)	37,000	$ 3.818
February 1, 2018 through December 31, 2018	37,000	3.818

On March 14, 2017, EOG executed the optional early termination provision granting EOG the right to terminate certain 2017 crude oil price swaps with notional volumes of 30,000 Bbld at a weighted average price of $50.05 per Bbl for the period March 1, 2017 through June 30, 2017. EOG received cash of $4.6 million for the early termination of these contracts, which are included in the table below. Presented below is a comprehensive summary of EOG's crude oil price swap contracts for the year ended December 31, 2017, with notional volumes expressed in Bbld and prices expressed in $/Bbl.

Crude Oil Price Swap Contracts

	Volume (Bbld)	Weighted Average Price ($/Bbl)
2017		
January 1, 2017 through February 28, 2017 (closed)	35,000	$ 50.04
March 1, 2017 through June 30, 2017 (closed)	30,000	50.05
2018		
January 1, 2018 through December 31, 2018	37,000	$ 56.48

On March 14, 2017, EOG entered into a crude oil price swap contract for the period March 1, 2017 through June 30, 2017, with notional volumes of 5,000 Bbld at a price of $48.81 per Bbl. This contract offset the remaining 2017 crude oil price swap contract for the same time period with notional volumes of 5,000 Bbld at a price of $50.00 per Bbl. The net cash EOG received for settling these contracts was $0.7 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, 2017, 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)
2017		
March 1, 2017 through November 30, 2017 (closed)	30,000	$ 3.10
2018		
March 1, 2018 through November 30, 2018	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, 2017, 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)
2017				
March 1, 2017 through November 30, 2017 (closed)	213,750	$ 3.44	171,000	$ 2.92
2018				
March 1, 2018 through November 30, 2018	120,000	$ 3.38	96,000	$ 2.94

EOG has also entered into natural gas collar contracts, which establish ceiling and floor prices for the sale of notional volumes of natural gas as specified in the collar contracts. The collars require that EOG pay the difference between the ceiling price and the Henry Hub Index Price in the event the Henry Hub Index Price is above the ceiling price. The collars grant EOG the right to receive the difference between the floor price and the Henry Hub Index Price in the event the Henry Hub Index Price is below the floor price. Presented below is a comprehensive summary of EOG's natural gas collar contracts for the year ended December 31, 2017, with notional volumes expressed in MMBtud and prices expressed in $/MMbtu.

Natural Gas Collar Contracts

		Weighted Average Price ($/MMbtu)	
	Volume (MMBtud)	Ceiling Price	Floor Price
2017			
March 1, 2017 through November 30, 2017 (closed)	80,000	$ 3.69	$ 3.20

The following table sets forth the amounts and classification of EOG's outstanding derivative financial instruments at December 31, 2017 and 2016, 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):

		Fair Value at December 31,	
Description	Location on Balance Sheet	2017	2016
Asset Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Assets from Price Risk Management Activities	$ 8	$ —
Noncurrent portion	Other Assets	—	1
Liability Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Liabilities from Price Risk Management Activities [(1)]	$ 50	$ 62
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, 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. At December 31, 2016, EOG's net accounts receivable balance related to United States, Canada and United Kingdom hydrocarbon sales included three receivable balances, each of which accounted for more than 10% of the total balance. The receivables were due from two petroleum refinery companies and one multinational oil and gas company. The related amounts were collected during early 2017. In 2017 and 2016, all natural gas from EOG's Trinidad operations was sold to the National Gas Company of Trinidad and Tobago Limited and its subsidiary; all crude oil and condensate from EOG's Trinidad operations was sold to the Petroleum Company of Trinidad and Tobago Limited; and 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 and 2016. EOG had no collateral posted and held no collateral at December 31, 2017 and 2016.

Substantially all of EOG's accounts receivable at December 31, 2017 and 2016 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, 2017, 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, 2017 and 2016. 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, 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
At December 31, 2016				
Financial Assets: (1)				
Natural Gas Options/Collars	$ —	$ 1	$ —	$ 1
Financial Liabilities: (2)				
Crude Oil Swaps	$ —	$ 36	$ —	$ 36
Natural Gas Swaps	—	4	—	4
Natural Gas Options/Collars	—	22	—	22

(1) $8 million is included in "Assets from Price Risk Management Activities" at December 31, 2017, and $1 million is included in "Other Assets" at December 31, 2016, on the Consolidated Balance Sheets.

(2) $50 million and $62 million is included in "Current Liabilities - Liabilities from Price Risk Management Activities" at December 31, 2017 and 2016, respectively, 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 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 and other property, plant and equipment 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. During 2016, proved oil and gas properties; other property, plant and equipment; and other assets with a carrying amount of $778 million were written down to their fair value of $587 million, resulting in pretax impairment charges of $191 million. Included in the $191 million pretax impairment charges were $61 million of impairments of obsolete inventory. In addition, EOG recorded pretax impairment charges in 2016 of $138 million for firm commitment contracts related to divested Haynesville natural gas 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. In certain instances, EOG utilized accepted offers from third-party purchasers as the basis for determining fair value.

Fair Value of Debt. At December 31, 2017 and 2016, respectively, EOG had outstanding $6,390 million and $6,990 million aggregate principal amount of senior notes, which had estimated fair values of approximately $6,602 million and $7,190 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 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. During 2016, proved oil and gas properties with a carrying amount of $643 million were written down to their fair value of $527 million, resulting in pretax impairment charges of $116 million. Impairments in 2017, 2016 and 2015 included domestic legacy natural gas assets. Amortization and impairments of unproved oil and gas property costs, including amortization of capitalized interest, were $211 million, $291 million and $288 million during 2017, 2016 and 2015, 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, 2017 and 2016 (in thousands):

	2017	2016
Carrying Amount at Beginning of Period	$ 912,926	$ 811,554
Liabilities Incurred (1)	54,764	212,739
Liabilities Settled (2)	(61,871)	(94,800)
Accretion	34,708	32,306
Revisions	(9,818)	(38,286)
Foreign Currency Translations	16,139	(10,587)
Carrying Amount at End of Period	$ 946,848	$ 912,926
Current Portion	$ 19,259	$ 18,516
Noncurrent Portion	$ 927,589	$ 894,410

(1) Includes $164 million in 2016 related to Yates transaction (see Note 17).
(2) 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, 2017, 2016 and 2015 are presented below (in thousands):

	2017	2016	2015
Balance at January 1	$ —	$ 8,955	$ 17,253
Additions Pending the Determination of Proved Reserves	27,487	6,688	24,640
Reclassifications to Proved Properties	(20,802)	(5,274)	(26,659)
Costs Charged to Expense [(1)]	(4,518)	(10,369)	(6,279)
Balance at December 31	$ 2,167	$ —	$ 8,955

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

At December 31, 2017, 2016 and 2015, all exploratory well costs had been capitalized for periods of less than one year.

17. Acquisitions and Divestitures

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.

During 2015, EOG completed acquisitions of approximately $481 million primarily to acquire proved crude oil properties and related assets in the Delaware Basin and gathering assets in the North Dakota Bakken.

During 2015, EOG recognized a net loss on asset dispositions of $(9) million and received proceeds of approximately $193 million primarily from sales of gathering and processing assets and other 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.

In 2017, EOG finalized its purchase price allocation in respect of the transactions with the Yates Entities, which resulted in net decreases of $35 million in Oil and Gas Properties and $32 million in Deferred Income Taxes, along with other immaterial changes.

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.

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 all 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 are to be 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, 2017. 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.

The impact of optimal completion techniques is a key factor in determining if 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, 2017, 2016 and 2015 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 13 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 31 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 President; 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, 2017, 2016 and 2015 covered producing areas containing 79%, 83% and 86%, 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 30, 2018, 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, 2017, 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, 2017, and the changes in the net proved reserves for each of the three years in the period ended December 31, 2017, as estimated by the Engineering and Acquisitions Department of EOG:

NET PROVED RESERVE SUMMARY

	United States	Trinidad	Other International [1]	Total
NET PROVED RESERVES				
Crude Oil (MBbl) [2]				
Net proved reserves at December 31, 2014	1,129,682	1,339	8,729	1,139,750
Revisions of previous estimates	(114,924)	(1)	—	(114,925)
Purchases in place	35,922	—	—	35,922
Extensions, discoveries and other additions	141,310	63	13	141,386
Sales in place	(730)	—	(10)	(740)
Production	(103,400)	(332)	(65)	(103,797)
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**
Natural Gas Liquids (MBbl) [2]				
Net proved reserves at December 31, 2014	466,930	—	138	467,068
Revisions of previous estimates	(113,290)	—	68	(113,222)
Purchases in place	8,251	—	—	8,251
Extensions, discoveries and other additions	49,147	—	—	49,147
Sales in place	(84)	—	(187)	(271)
Production	(28,079)	—	(19)	(28,098)
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**

	United States	Trinidad	Other International [1]	Total
Natural Gas (Bcf) [3]				
Net proved reserves at December 31, 2014	4,905.5	405.6	31.5	5,342.6
Revisions of previous estimates	(1,453.1)	16.8	5.6	(1,430.7)
Purchases in place	72.3	—	—	72.3
Extensions, discoveries and other additions	306.3	21.7	4.4	332.4
Sales in place	(3.9)	—	(11.1)	(15.0)
Production	(337.3)	(127.5)	(10.9)	(475.7)
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**
Oil Equivalents (MBoe) [2]				
Net proved reserves at December 31, 2014	2,414,202	68,937	14,117	2,497,256
Revisions of previous estimates	(470,401)	2,802	995	(466,604)
Purchases in place	56,215	—	—	56,215
Extensions, discoveries and other additions	241,513	3,682	736	245,931
Sales in place	(1,467)	—	(2,039)	(3,506)
Production	(187,701)	(21,578)	(1,896)	(211,175)
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**

(1) Other International includes EOG's United Kingdom, China, Canada and Argentina operations. 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 2017, EOG added 421 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 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.

During 2015, EOG added 246 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 77% of the 2015 reserve additions were crude oil and condensate and NGLs, and 98% were in the United States. Sales in place of 4 MMBoe were primarily related to the disposition of certain producing natural gas assets in Canada, the Permian Basin and the Upper Gulf Coast. Negative revisions of previous estimates of 467 MMBoe for 2015 included a negative revision of 574 MMBoe primarily due to decreases in the average crude oil and natural gas prices used in the December 31, 2015, reserves estimation as compared to the prices used in the prior year estimate. The primary plays affected were the Uinta and Green River basins in the Rocky Mountain area, the Permian Basin and the Barnett Shale. Revisions other than price resulted primarily from improved recovery in the Eagle Ford.

	United States	Trinidad	Other International (1)	Total
NET PROVED DEVELOPED RESERVES				
Crude Oil (MBbl)				
December 31, 2014	493,694	1,339	115	495,148
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
Natural Gas Liquids (MBbl)				
December 31, 2014	264,611	—	138	264,749
December 31, 2015	205,898	—	—	205,898
December 31, 2016	230,219	—	—	230,219
December 31, 2017	286,872	—	—	286,872
Natural Gas (Bcf)				
December 31, 2014	3,102.8	396.9	28.6	3,528.3
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
Oil Equivalents (MBoe)				
December 31, 2014	1,275,447	67,484	5,016	1,347,947
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
NET PROVED UNDEVELOPED RESERVES				
Crude Oil (MBbl)				
December 31, 2014	635,988	—	8,614	644,602
December 31, 2015	643,790	—	8,604	652,394
December 31, 2016	660,690	—	—	660,690
December 31, 2017	698,666	—	71	698,737
Natural Gas Liquids (MBbl)				
December 31, 2014	202,319	—	—	202,319
December 31, 2015	176,977	—	—	176,977
December 31, 2016	186,147	—	—	186,147
December 31, 2017	216,601	—	—	216,601
Natural Gas (Bcf)				
December 31, 2014	1,802.7	8.7	2.9	1,814.3
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
Oil Equivalents (MBoe)				
December 31, 2014	1,138,755	1,453	9,101	1,149,309
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

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

Net Proved Undeveloped Reserves. The following table presents the changes in EOG's total proved undeveloped reserves during 2017, 2016 and 2015 (in MBoe):

	2017	2016	2015
Balance at January 1	1,053,027	1,045,640	1,149,309
Extensions and Discoveries	237,378	138,101	205,152
Revisions	33,127	64,413	(241,973)
Acquisition of Reserves	—	—	54,458
Sale of Reserves	(8,253)	(45,917)	—
Conversion to Proved Developed Reserves	(152,644)	(149,210)	(121,306)
Balance at December 31	1,162,635	1,053,027	1,045,640

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 (see discussion of technology employed on pages F-38 and F-39 of this Annual Report on Form 10-K), 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. 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, 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. All PUDs for 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, 2015, total PUDs decreased by 104 MMBoe to 1,046 MMBoe. EOG added approximately 52 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 153 MMBoe. The PUD additions were primarily in the Permian Basin and, to a lesser extent, the Eagle Ford and the Rocky Mountain area, and 80% of the additions were crude oil and condensate and NGLs. During 2015, EOG drilled and transferred 121 MMBoe of PUDs to proved developed reserves at a total capital cost of $2,349 million. Revisions of PUDs totaled negative 242 MMBoe, primarily due to decreases in the average crude oil and natural gas prices used in the December 31, 2015, reserves estimation as compared to the prices used in the prior year estimate. During 2015, EOG did not sell any PUDs and acquired 54 MMBoe of PUDs.

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, 2017 and 2016:

	2017	2016
Proved properties	$ 48,845,672	$ 45,751,965
Unproved properties	3,710,069	3,840,126
Total	52,555,741	49,592,091
Accumulated depreciation, depletion and amortization	(29,191,247)	(26,247,062)
Net capitalized costs	**$ 23,364,494**	**$ 23,345,029**

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.

The following table sets forth costs incurred related to EOG's oil and gas activities for the years ended December 31, 2017, 2016 and 2015:

	United States	Trinidad	Other International (1)	Total
2017				
Acquisition Costs of Properties				
Unproved (2)	$ 424,118	$ 2,422	$ —	$ 426,540
Proved (3)	72,584	—	—	72,584
Subtotal	496,702	2,422	—	499,124
Exploration Costs	144,499	62,547	16,553	223,599
Development Costs (4)	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 (5)	$ 3,216,598	$ —	$ 36	$ 3,216,634
Proved (6)	749,023	—	—	749,023
Subtotal	3,965,621	—	36	3,965,657
Exploration Costs	156,295	2,695	6,761	165,751
Development Costs (7)	2,252,713	72,147	(10,984)	2,313,876
Total	$ 6,374,629	$ 74,842	$ (4,187)	$ 6,445,284
2015				
Acquisition Costs of Properties				
Unproved	$ 133,801	$ —	$ 56	$ 133,857
Proved	480,617	—	—	480,617
Subtotal	614,418	—	56	614,474
Exploration Costs	206,814	22,837	23,041	252,692
Development Costs (8)	3,847,813	102,715	110,589	4,061,117
Total	$ 4,669,045	$ 125,552	$ 133,686	$ 4,928,283

(1) Other International primarily consists of EOG's United Kingdom, China, Canada and Argentina operations. The Argentina operations were sold in the third quarter of 2016.
(2) Includes non-cash unproved leasehold acquisition costs of $256 million related to property exchanges.
(3) Includes non-cash proved property acquisition costs of $26 million related to property exchanges.
(4) 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.
(5) Includes non-cash unproved leasehold acquisition costs of $3,102 million related to the Yates transaction.
(6) Includes non-cash proved property acquisition costs of $732 million related to the Yates transaction.
(7) 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.
(8) Includes Asset Retirement Costs of $32 million, $15 million and $6 million for the United States, Trinidad and Other International, respectively. Excludes other property, plant and equipment.

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, 2017, 2016 and 2015:

	United States	Trinidad	Other International [2]	Total
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)
2015				
Crude Oil and Condensate, Natural Gas Liquids and Natural Gas Revenues	$ 5,962,753	$ 381,761	$ 58,744	$ 6,403,258
Other	47,464	(3)	448	47,909
Total	6,010,217	381,758	59,192	6,451,167
Exploration Costs	139,753	2,071	7,670	149,494
Dry Hole Costs	956	5,635	8,155	14,746
Transportation Costs	838,428	1,290	9,601	849,319
Production Costs	1,486,189	28,862	66,080	1,581,131
Impairments	6,402,908	—	210,638	6,613,546
Depreciation, Depletion and Amortization	3,017,386	154,588	18,469	3,190,443
Income (Loss) Before Income Taxes	(5,875,403)	189,312	(261,421)	(5,947,512)
Income Tax Provision	(2,128,183)	43,739	(2,111)	(2,086,555)
Results of Operations	$ (3,747,220)	$ 145,573	$ (259,310)	$ (3,860,957)

(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, 2017.

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

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, 2017, 2016 and 2015:

	United States	Trinidad	Other International (1)	Composite
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
Year Ended December 31, 2015	$ 5.81	$ 1.29	$ 33.78	$ 5.85

(1) Other International primarily consists of EOG's United Kingdom, China, Canada and Argentina operations. 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 2017, 2016 and 2015. 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.

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, 2017, 2016 and 2015:

	United States	Trinidad	Other International (1)	Total
2017				
Future cash inflows (2)	$ 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 (3)	$ 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
2015				
Future cash inflows (4)	$ 67,242,928	$ 954,779	$ 522,941	$ 68,720,648
Future production costs	(31,707,743)	(183,607)	(169,505)	(32,060,855)
Future development costs	(15,579,923)	(140,541)	(65,347)	(15,785,811)
Future income taxes	(4,400,542)	(215,659)	—	(4,616,201)
Future net cash flows	15,554,720	414,972	288,089	16,257,781
Discount to present value at 10% annual rate	(6,589,253)	(33,848)	(13,284)	(6,636,385)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 8,965,467	$ 381,124	$ 274,805	$ 9,621,396

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

(2) 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.

(3) 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.

(4) Estimated crude oil prices used to calculate 2015 future cash inflows for the United States, Trinidad and Other International were $49.58, $38.83 and $47.76, respectively. Estimated NGL price used to calculate 2015 future cash inflows for the United States was $15.17. Estimated natural gas prices used to calculate 2015 future cash inflows for the United States, Trinidad and Other International were $2.15, $2.88 and $5.60, respectively.

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, 2017:

	United States	Trinidad	Other International (1)	Total
December 31, 2014	$ 26,704,041	$ 682,536	$ 536,841	$ 27,923,418
Sales and transfers of oil and gas produced, net of production costs	(3,685,600)	(351,606)	16,489	(4,020,717)
Net changes in prices and production costs	(29,993,699)	(370,503)	(305,148)	(30,669,350)
Extensions, discoveries, additions and improved recovery, net of related costs	1,028,410	47,613	19,875	1,095,898
Development costs incurred	2,135,800	500	1,400	2,137,700
Revisions of estimated development cost	4,087,093	(34,647)	26,935	4,079,381
Revisions of previous quantity estimates	(4,084,572)	33,285	(587)	(4,051,874)
Accretion of discount	3,699,330	104,464	53,685	3,857,479
Net change in income taxes	9,550,847	177,576	—	9,728,423
Purchases of reserves in place	123,542	—	—	123,542
Sales of reserves in place	(23,424)	—	(13,664)	(37,088)
Changes in timing and other	(576,301)	91,906	(61,021)	(545,416)
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**

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

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

Quarter Ended	Mar 31	Jun 30	Sep 30	Dec 31
2017				
Net 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) (1)	10,865	39,414	45,439	(2,017,115)
Net Income	$ 28,517	$ 23,053	$ 100,541	$ 2,430,468
Net Income Per Share (2)				
Basic	$ 0.05	$ 0.04	$ 0.17	$ 4.22
Diluted	$ 0.05	$ 0.04	$ 0.17	$ 4.20
Average Number of Common Shares				
Basic	573,935	574,439	574,783	575,394
Diluted	578,593	578,483	578,736	579,203
2016				
Net Operating Revenues and Other	$ 1,354,349	$ 1,775,740	$ 2,118,504	$ 2,402,039
Operating Income (Loss)	$ (638,141)	$ (288,173)	$ (193,480)	$ (105,487)
Loss Before Income Taxes	$ (710,968)	$ (380,277)	$ (272,250)	$ (194,010)
Income Tax Benefit	(239,192)	(87,719)	(82,250)	(51,658)
Net Income (Loss)	$ (471,776)	$ (292,558)	$ (190,000)	$ (142,352)
Net Income (Loss) Per Share (2)				
Basic	$ (0.86)	$ (0.53)	$ (0.35)	$ (0.25)
Diluted	$ (0.86)	$ (0.53)	$ (0.35)	$ (0.25)
Average Number of Common Shares				
Basic	546,715	547,335	547,838	567,337
Diluted	546,715	547,335	547,838	567,337

(1) Includes an income tax benefit of approximately $2.2 billion for the quarter ended December 31, 2017, primarily due to the enactment of the Tax Cuts and Jobs Act in December 2017. See Note 6 to the Consolidated Financial Statements.

(2) The sum of quarterly net income (loss) per share may not agree with total year net income (loss) per share as each quarterly computation is based on the weighted average of common shares outstanding.

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EXHIBITS

Exhibits not incorporated herein by reference to a prior filing are designated by (i) an asterisk (*) and are filed herewith; or (ii) a pound sign (#) and are not filed herewith, and, pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, the registrant hereby agrees to furnish a copy of such exhibit to the United States Securities and Exchange Commission (SEC) upon request.

Exhibit Number		Description
***2.1	-	Agreement and Plan of Merger, dated as of September 2, 2016, by an among EOG, ERI Holdings I, Inc. and Yates Petroleum Corporation (Exhibit 2.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2016) (SEC File No. 001-09743).
3.1(a)	-	Restated Certificate of Incorporation, dated September 3, 1987 (Exhibit 3.1(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008) (SEC File No. 001-09743).
3.1(b)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 5, 1993 (Exhibit 4.1(b) to EOG's Registration Statement on Form S-8, SEC File No. 33-52201, filed February 8, 1994).
3.1(c)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated June 14, 1994 (Exhibit 4.1(c) to EOG's Registration Statement on Form S-8, SEC File No. 33-58103, filed March 15, 1995).
3.1(d)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated June 11, 1996 (Exhibit 3(d) to EOG's Registration Statement on Form S-3, SEC File No. 333-09919, filed August 9, 1996).
3.1(e)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 7, 1997 (Exhibit 3(e) to EOG's Registration Statement on Form S-3, SEC File No. 333-44785, filed January 23, 1998).
3.1(f)	-	Certificate of Ownership and Merger Merging EOG Resources, Inc. into Enron Oil & Gas Company, dated August 26, 1999 (Exhibit 3.1(f) to EOG's Annual Report on Form 10-K for the year ended December 31, 1999) (SEC File No. 001-09743).
3.1(g)	-	Certificate of Designations of Series E Junior Participating Preferred Stock, dated February 14, 2000 (Exhibit 2 to EOG's Registration Statement on Form 8-A, SEC File No. 001-09743, filed February 18, 2000).
3.1(h)	-	Certificate of Elimination of the Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series A, dated September 13, 2000 (Exhibit 3.1(j) to EOG's Registration Statement on Form S-3, SEC File No. 333-46858, filed September 28, 2000).
3.1(i)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series C, dated September 13, 2000 (Exhibit 3.1(k) to EOG's Registration Statement on Form S-3, SEC File No. 333-46858, filed September 28, 2000).
3.1(j)	-	Certificate of Elimination of the Flexible Money Market Cumulative Preferred Stock, Series D, dated February 24, 2005 (Exhibit 3.1(k) to EOG's Annual Report on Form 10-K for the year ended December 31, 2004) (SEC File No. 001-09743).
3.1(k)	-	Amended Certificate of Designations of Series E Junior Participating Preferred Stock, dated March 7, 2005 (Exhibit 3.1(m) to EOG's Annual Report on Form 10-K for the year ended December 31, 2007) (SEC File No. 001-09743).
3.1(l)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated May 3, 2005 (Exhibit 3.1(l) to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005) (SEC File No. 001-09743).
3.1(m)	-	Certificate of Elimination of Fixed Rate Cumulative Perpetual Senior Preferred Stock, Series B, dated March 6, 2008 (Exhibit 3.1 to EOG's Current Report on Form 8-K, filed March 6, 2008) (SEC File No. 001-09743).
3.1(n)	-	Certificate of Amendment of Restated Certificate of Incorporation, dated April 28, 2017 (Exhibit 3.1 to EOG's Current Report on Form 8-K, filed May 2, 2017) (SEC File No. 001-09743).
3.2	-	Bylaws, dated August 23, 1989, as amended and restated effective as of September 22, 2015 (Exhibit 3.1 to EOG's Current Report on Form 8-K, filed September 28, 2015) (SEC File No. 001-09743).
4.1	-	Specimen of Certificate evidencing EOG's Common Stock (Exhibit 3.3 to EOG's Annual Report on Form 10-K for the year ended December 31, 1999) (SEC File No. 001-09743).
4.2	-	Indenture, dated as of September 1, 1991, between Enron Oil & Gas Company (predecessor to EOG) and The Bank of New York Mellon Trust Company, N.A. (as successor in interest to JPMorgan Chase Bank, N.A. (formerly, Texas Commerce Bank National Association)), as Trustee (Exhibit 4(a) to EOG's Registration Statement on Form S-3, SEC File No. 33-42640, filed in paper format on September 6, 1991).

Exhibit Number		Description
4.3(a)	-	Officers' Certificate Establishing 6.125% Senior Notes due 2013 and 6.875% Senior Notes due 2018 of EOG, dated September 30, 2008 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 30, 2008) (SEC File No. 001-09743).
4.3(b)	-	Form of Global Note with respect to the 6.875% Senior Notes due 2018 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed September 30, 2008) (SEC File No. 001-09743).
#4.4(a)	-	Certificate, dated April 3, 1998, of the Senior Vice President and Chief Financial Officer of Enron Oil & Gas Company (predecessor to EOG) establishing the terms of the 6.65% Notes due April 1, 2028 of Enron Oil & Gas Company.
#4.4(b)	-	Global Note with respect to the 6.65% Notes due April 1, 2028 of Enron Oil & Gas Company (predecessor to EOG).
4.5	-	Indenture, dated as of May 18, 2009, between EOG and Wells Fargo Bank, National Association, as Trustee (Exhibit 4.9 to EOG's Registration Statement on Form S-3, SEC File No. 333-159301, filed May 18, 2009).
4.6(a)	-	Officers' Certificate Establishing 5.625% Senior Notes due 2019 of EOG, dated May 21, 2009 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed May 21, 2009) (SEC File No. 001-09743).
4.6(b)	-	Form of Global Note with respect to the 5.625% Senior Notes due 2019 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed May 21, 2009) (SEC File No. 001-09743).
4.7(a)	-	Officers' Certificate Establishing 2.95% Senior Notes due 2015 and 4.40% Senior Notes due 2020 of EOG, dated May 20, 2010 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed May 26, 2010) (SEC File No. 001-09743).
4.7(b)	-	Form of Global Note with respect to the 4.40% Senior Notes due 2020 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed May 26, 2010) (SEC File No. 001-09743).
4.8(a)	-	Officers' Certificate Establishing 2.500% Senior Notes due 2016, 4.100% Senior Notes due 2021 and Floating Rate Senior Notes due 2014 of EOG, dated November 23, 2010 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed November 24, 2010) (SEC File No. 001-09743).
4.8(b)	-	Form of Global Note with respect to the 4.100% Senior Notes due 2021 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed November 24, 2010) (SEC File No. 001-09743).
4.9(a)	-	Officers' Certificate Establishing 2.625% Senior Notes due 2023 of EOG, dated September 10, 2012 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 11, 2012) (SEC File No. 001-09743).
4.9(b)	-	Form of Global Note with respect to the 2.625% Senior Notes due 2023 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed September 11, 2012) (SEC File No. 001-09743).
4.10(a)	-	Officers' Certificate Establishing 2.45% Senior Notes due 2020 of EOG, dated March 21, 2014 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed March 25, 2014) (SEC File No. 001-09743).
4.10(b)	-	Form of Global Note with respect to the 2.45% Senior Notes due 2020 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed March 25, 2014) (SEC File No. 001-09743).
4.11(a)	-	Officers' Certificate Establishing 3.15% Senior Notes due 2025 and 3.90% Senior Notes due 2035 of EOG, dated March 17, 2015 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed March 19, 2015) (SEC File No. 001-09743).
4.11(b)	-	Form of Global Note with respect to the 3.15% Senior Notes due 2025 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed March 19, 2015) (SEC File No. 001-09743).
4.11(c)	-	Form of Global Note with respect to the 3.90% Senior Notes due 2035 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed March 19, 2015) (SEC File No. 001-09743).
4.12(a)	-	Officers' Certificate Establishing 4.15% Senior Notes due 2026 and 5.10% Senior Notes due 2036 of EOG, dated January 14, 2016 (Exhibit 4.2 to EOG's Current Report on Form 8-K, filed January 15, 2016) (SEC File No. 001-09743).
4.12(b)	-	Form of Global Note with respect to the 4.15% Senior Notes due 2026 of EOG (Exhibit 4.3 to EOG's Current Report on Form 8-K, filed January 15, 2016) (SEC File No. 001-09743).
4.12(c)	-	Form of Global Note with respect to the 5.10% Senior Notes due 2036 of EOG (Exhibit 4.4 to EOG's Current Report on Form 8-K, filed January 15, 2016) (SEC File No. 001-09743).

Exhibit Number		Description
10.1(a)+	-	EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, effective as of May 8, 2008 (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(b)+	-	First Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of September 4, 2008 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008) (SEC File No. 001-09743).
10.1(c)+	-	Second Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of January 1, 2010 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010) (SEC File No. 001-09743).
10.1(d)+	-	Third Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of September 26, 2012 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012) (SEC File No. 001-09743).
10.1(e)+	-	Form of Stock Option Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made prior to February 23, 2011) (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(f)+	-	Form of Stock Option Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after February 23, 2011) (Exhibit 10.3 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011) (SEC File No. 001-09743).
10.1(g)+	-	Form of Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made prior to February 23, 2011) (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(h)+	-	Form of Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made on or after February 23, 2011) (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011) (SEC File No. 001-09743).
10.1(i)	-	Form of Nonemployee Director Stock-Settled Stock Appreciation Right Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(j)+	-	Form of Restricted Stock Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.5 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(k)+	-	Form of Restricted Stock Unit Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.6 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(l)	-	Form of Nonemployee Director Restricted Stock Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.7 to EOG's Current Report on Form 8-K, filed May 14, 2008) (SEC File No. 001-09743).
10.1(m)	-	Form of Nonemployee Director Restricted Stock Unit Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.3 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012) (SEC File No. 001-09743).
10.1(n)+	-	Form of Performance Unit Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed October 1, 2012) (SEC File No. 001-09743).
10.2(a)+	-	Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, effective as of May 2, 2013 (Exhibit 4.4 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(b)+	-	Form of Restricted Stock Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made prior to September 25, 2017) (Exhibit 4.5 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(c)+	-	Form of Restricted Stock Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made effective September 25, 2017 and subsequent grants) (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed September 29, 2017) (SEC File No. 001-09743).
10.2(d)+	-	Form of Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made prior to September 25, 2017) (Exhibit 4.6 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).

Exhibit Number		Description
10.2(e)+	-	Form of Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made effective September 25, 2017 and subsequent grants) (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed September 29, 2017) (SEC File No. 001-09743).
10.2(f)+	-	Form of Stock-Settled Stock Appreciation Right Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made prior to September 25, 2017) (Exhibit 4.7 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(g)+	-	Form of Stock Settled Stock Appreciation Right Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to grants made effective September 25, 2017 and subsequent grants) (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed September 29, 2017) (SEC File No. 001-09743).
10.2(h)+	-	Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to annual grants made prior to September 22, 2014) (Exhibit 4.8 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(i)+	-	Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to annual grants made on or after September 22, 2014 and prior to September 27, 2016) (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014) (SEC File No. 001-09743).
10.2(j)+	-	Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to annual grants made on or after September 27, 2016 and prior to September 25, 2017) (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2016) (SEC File No. 001-09743).
10.2(k)+	-	Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to specific grants made effective December 13, 2016) (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed December 19, 2016) (SEC File No. 001-09743).
10.2(l)+	-	Form of Performance Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (applicable to annual grants made effective September 25, 2017 and subsequent grants) (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed September 29, 2017) (SEC File No. 001-09743).
10.2(m)+	-	Form of Performance Stock Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 4.9 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(n)	-	Form of Non-Employee Director Restricted Stock Unit Award Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 4.10 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.2(o)	-	Form of Non-Employee Director Stock-Settled Stock Appreciation Right Agreement for Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (Exhibit 4.11 to EOG's Registration Statement on Form S-8, SEC File No. 333-188352, filed May 3, 2013).
10.3(a)+	-	EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan - Plan Document, effective as of December 16, 2008 (Exhibit 10.2(a) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008) (SEC File No. 001-09743).
10.3(b)+	-	EOG Resources, Inc. 409A Deferred Compensation Plan - Nonqualified Supplemental Deferred Compensation Plan - Adoption Agreement, originally dated as of December 16, 2008 (and as amended through February 24, 2012 (including an amendment to Item 7 thereof, effective January 1, 2012, with respect to the deferral of restricted stock units)) (Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2011) (originally filed as Exhibit 10.2(b) to EOG's Annual Report on Form 10-K for the year ended December 31, 2008) (SEC File No. 001-09743).
10.3(c)+	-	First Amendment to the EOG Resources, Inc. 409A Deferred Compensation Plan, effective as of January 1, 2013 (Exhibit 10.8 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013) (SEC File No. 001-09743).
10.3(d)+	-	Amended and Restated 1996 Deferral Plan (Exhibit 4.4 to EOG's Registration Statement on Form S-8, SEC File No. 333-84014, filed March 8, 2002).

Exhibit Number		Description
10.3(e)+	-	First Amendment to Amended and Restated 1996 Deferral Plan, effective as of September 10, 2002 (Exhibit 10.9(e) to EOG's Annual Report on Form 10-K for the year ended December 31, 2002) (SEC File No. 001-09743).
10.4(a)+	-	Change of Control Agreement between EOG and William R. Thomas, effective as of January 12, 2011 (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011) (SEC File No. 001-09743).
10.4(b)+	-	First Amendment to Change of Control Agreement between EOG and William R. Thomas, effective as of September 13, 2011 (Exhibit 10.2 to EOG's Current Report on Form 8-K, filed September 13, 2011) (SEC File No. 001-09743).
10.4(c)+	-	Second Amendment to Change of Control Agreement between EOG and William R. Thomas, effective as of September 4, 2013 (Exhibit 10.2 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013) (SEC File No. 001-09743).
10.5(a)+	-	Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of June 15, 2005 (Exhibit 99.9 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.5(b)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of April 30, 2009 (Exhibit 10.3(b) to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009) (SEC File No. 001-09743).
10.5(c)+	-	Second Amendment to Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of September 13, 2011 (Exhibit 10.3 to EOG's Current Report on Form 8-K, filed September 13, 2011) (SEC File No. 001-09743).
10.5(d)+	-	Third Amendment to Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of September 4, 2013 (Exhibit 10.3 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013) (SEC File No. 001-09743).
10.6(a)+	-	Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of June 15, 2005 (Exhibit 99.11 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).
10.6(b)+	-	First Amendment to Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of April 30, 2009 (Exhibit 10.5 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009) (SEC File No. 001-09743).
10.6(c)+	-	Second Amendment to Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of September 13, 2011 (Exhibit 10.4 to EOG's Current Report on Form 8-K, filed September 13, 2011) (SEC File No. 001-09743).
10.7(a)+	-	Change of Control Agreement by and between EOG and Michael P. Donaldson, effective as of May 3, 2012 (Exhibit 10.1 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012) (SEC File No. 001-09743).
10.7(b)+	-	First Amendment to Change of Control Agreement between EOG and Michael P. Donaldson, effective as of September 4, 2013 (Exhibit 10.7 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013) (SEC File No. 001-09743).
10.8(a)+	-	Change of Control Agreement by and between EOG and Lloyd W. Helms, effective as of June 27, 2013 (Exhibit 10.9 to EOG's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013) (SEC File No. 001-09743).
10.8(b)+	-	First Amendment to Change of Control Agreement between EOG and Lloyd W. Helms, Jr., effective as of September 4, 2013 (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013) (SEC File No. 001-09743).
10.9+	-	Change of Control Agreement by and between EOG and David W. Trice, effective as of September 4, 2013 (Exhibit 10.5 to EOG's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013) (SEC File No. 001-09743).
*10.10+	-	Change of Control Agreement by and between EOG and Ezra Y. Yacob, effective as of January 26, 2018.
10.11(a)+	-	EOG Resources, Inc. Change of Control Severance Plan, as amended and restated effective as of June 15, 2005 (Exhibit 99.12 to EOG's Current Report on Form 8-K, filed June 21, 2005) (SEC File No. 001-09743).

Exhibit Number		Description
10.11(b)+	-	First Amendment to the EOG Resources, Inc. Change of Control Severance Plan, effective as of April 30, 2009 (Exhibit 10.6 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009) (SEC File No. 001-09743).
10.12+	-	EOG Resources, Inc. Amended and Restated Executive Officer Annual Bonus Plan (Exhibit 10.4 to EOG's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010) (SEC File No. 001-09743).
10.13(a)+	-	EOG Resources, Inc. Employee Stock Purchase Plan (Exhibit 4.4 to EOG's Registration Statement on Form S-8, SEC File No. 333-62256, filed June 4, 2001).
10.13(b)+	-	Amendment to EOG Resources, Inc. Employee Stock Purchase Plan, dated effective as of January 1, 2010 (Exhibit 4.3(b) to EOG's Registration Statement on Form S-8, SEC File No. 333-166518, filed May 4, 2010).
10.14	-	Revolving Credit Agreement, dated as of July 21, 2015, among EOG, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (Exhibit 10.1 to EOG's Current Report on Form 8-K, filed July 24, 2015) (SEC File No. 001-09743).
* 12	-	Computation of Ratio of Earnings to Fixed Charges.
* 21	-	Subsidiaries of EOG, as of December 31, 2017.
* 23.1	-	Consent of DeGolyer and MacNaughton.
* 23.2	-	Consent of Deloitte & Touche LLP.
* 24	-	Powers of Attorney.
* 31.1	-	Section 302 Certification of Annual Report of Principal Executive Officer.
* 31.2	-	Section 302 Certification of Annual Report of Principal Financial Officer.
* 32.1	-	Section 906 Certification of Annual Report of Principal Executive Officer.
* 32.2	-	Section 906 Certification of Annual Report of Principal Financial Officer.
* 95	-	Mine Safety Disclosure Exhibit.
* 99.1	-	Opinion of DeGolyer and MacNaughton dated January 30, 2018.
* **101.INS	-	XBRL Instance Document.
* **101.SCH	-	XBRL Schema Document.
* **101.CAL	-	XBRL Calculation Linkbase Document.
* **101.LAB	-	XBRL Label Linkbase Document.
* **101.PRE	-	XBRL Presentation Linkbase Document.
* **101.DEF	-	XBRL Definition Linkbase Document.

*Exhibits filed herewith

**Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) for Each of the Three Years in the Period Ended December 31, 2017, (ii) the Consolidated Balance Sheets - December 31, 2017 and 2016, (iii) the Consolidated Statements of Stockholders' Equity for Each of the Three Years in the Period Ended December 31, 2017, (iv) the Consolidated Statements of Cash Flows for Each of the Three Years in the Period Ended December 31, 2017 and (v) the Notes to Consolidated Financial Statements.

***Annexes, exhibit and disclosure schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A list of the annexes and exhibit is included after the table of contents in the Agreement and Plan of Merger. The disclosure schedules set forth various matters in respect of the representations, warranties, covenants and other provisions of the Agreement and Plan of Merger. The registrant agrees to furnish a supplemental copy of any such omitted annexes, exhibit or disclosure schedules to the SEC upon request.

+ Management contract, compensatory plan or arrangement

SIGNATURES

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

EOG RESOURCES, INC.
(Registrant)

Date: February 27, 2018

By: /s/ TIMOTHY K. DRIGGERS
Timothy K. Driggers
Executive Vice President and Chief Financial Officer
(Principal Financial Officer and Duly Authorized Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities with EOG Resources, Inc. indicated and on the 27th day of February, 2018.

Signature	Title
/s/ WILLIAM R. THOMAS (William R. Thomas)	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)
/s/ TIMOTHY K. DRIGGERS (Timothy K. Driggers)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ ANN D. JANSSEN (Ann D. Janssen)	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
* (Janet F. Clark)	Director
* (Charles R. Crisp)	Director
* (Robert P. Daniels)	Director
* (James C. Day)	Director
* (C. Christopher Gaut)	Director
* (Donald F. Textor)	Director
* (Frank G. Wisner)	Director

*By: /s/ MICHAEL P. DONALDSON
(Michael P. Donaldson)
(Attorney-in-fact for persons indicated)

EOG RESOURCES, INC.

Direct After-Tax Rate of Return (ATROR)

The calculation of our direct after-tax rate of return (ATROR) with respect to our capital expenditure program for a particular play, well or drilling program is based on the estimated recoverable reserves ("net" to EOG's interest) for all wells in such play, such well or all wells in such drilling program (as the case may be), the estimated net present value (NPV) of the future net cash flows from such reserves (for which we utilize certain assumptions regarding future commodity prices and operating costs) and our direct net costs incurred in drilling or acquiring (as the case may be) such wells or well (as the case may be). As such, our direct ATROR with respect to our capital expenditures for a particular play, well or drilling program cannot be calculated from our consolidated financial statements.

Direct ATROR

Based on Cash Flow and Time Value of Money

- Estimated future commodity prices and operating costs
- Costs incurred to drill, complete and equip a well, including facilities

Excludes Indirect Capital

- Gathering and Processing and other Midstream
- Land, Seismic, Geological and Geophysical

Payback ~12 Months on 100% Direct ATROR Wells

First Five Years ~1/2 Estimated Ultimate Recovery Produced but ~3/4 of NPV Captured

Return on Equity / Return on Capital Employed

Based on GAAP Accrual Accounting

Includes All Indirect Capital and Growth Capital for Infrastructure

- Eagle Ford, Bakken, Permian Facilities
- Gathering and Processing

Includes Legacy Gas Capital and Capital from Mature Wells

EOG RESOURCES, INC.

Quantitative Reconciliation of After-Tax Net Interest Expense (Non-GAAP), Adjusted Net Income (Loss) (Non-GAAP), Net Debt (Non-GAAP) and Total Capitalization (Non-GAAP) as used in the Calculations of Return on Capital Employed (Non-GAAP) and Return on Equity (Non-GAAP) to Net Interest Expense (GAAP), Net Income (Loss) (GAAP), Current and Long-Term Debt (GAAP) and Total Capitalization (GAAP), Respectively

(Unaudited; in millions, except ratio data)

The following chart reconciles Net Interest Expense (GAAP), Net Income (Loss) (GAAP), Current and Long-Term Debt (GAAP) and Total Capitalization (GAAP) to After-Tax Net Interest Expense (Non-GAAP), Adjusted Net Income (Loss) (Non-GAAP), Net Debt (Non-GAAP) and Total Capitalization (Non-GAAP), respectively, as used in the Return on Capital Employed (ROCE) and Return on Equity (ROE) calculations. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who utilize After-Tax Net Interest Expense, Adjusted Net Income (Loss), Net Debt and Total Capitalization (Non-GAAP) in their ROCE and ROE calculations. EOG management uses this information for purposes of comparing its financial performance with the financial performance of other companies in the industry.

	2017	2016	2015	2014	2013
Return on Capital Employed (ROCE) (Non-GAAP)					
Net Interest Expense (GAAP)	$ 274	$ 282	$ 237	$ 201	
Tax Benefit Imputed (based on 35%)	(96)	(99)	(83)	(70)	
After-Tax Net Interest Expense (Non-GAAP) - (a)	$ 178	$ 183	$ 154	$ 131	
Net Income (Loss) (GAAP) - (b)	$ 2,583	$ (1,097)	$ (4,525)	$ 2,915	
Adjustments to Net Income (Loss), Net of Tax (See Accompanying Schedules)	(1,934)(a)	204 (b)	4,559 (c)	(199)(d)	
Adjusted Net Income (Loss) (Non-GAAP) - (c)	$ 649	$ (893)	$ 34	$ 2,716	
Total Stockholders' Equity Before Retained Earnings Adjustment (GAAP) - (d)	$ 16,283	$ 13,982	$ 12,943	$ 17,713	$ 15,418
Less: Tax Reform Impact	(2,169)	-	-	-	-
Total Stockholders' Equity (Non-GAAP) - (e)	$ 14,114	$ 13,982	$ 12,943	$ 17,713	$ 15,418
Average Total Stockholders' Equity (GAAP) * - (f)	$ 15,133	$ 13,463	$ 15,328	$ 16,566	
Average Total Stockholders' Equity (Non-GAAP) * - (g)	$ 14,048	$ 13,463	$ 15,328	$ 16,566	
Current and Long-Term Debt (GAAP) - (h)	$ 6,387	$ 6,986	$ 6,655	$ 5,906	$ 5,909
Less: Cash	(834)	(1,600)	(719)	(2,087)	(1,318)
Net Debt (Non-GAAP) - (i)	$ 5,553	$ 5,386	$ 5,936	$ 3,819	$ 4,591
Total Capitalization (GAAP) - (d) + (h)	$ 22,670	$ 20,968	$ 19,598	$ 23,619	$ 21,327
Total Capitalization (Non-GAAP) - (e) + (i)	$ 19,667	$ 19,368	$ 18,879	$ 21,532	$ 20,009
Average Total Capitalization (Non-GAAP) * - (j)	$ 19,518	$ 19,124	$ 20,206	$ 20,771	
ROCE (GAAP Net Income) - [(a) + (b)] / (j)	**14.1%**	**-4.8%**	**-21.6%**	**14.7%**	
ROCE (Non-GAAP Adjusted Net Income) - [(a) + (c)] / (j)	**4.2%**	**-3.7%**	**0.9%**	**13.7%**	
Return on Equity (ROE)					
ROE (GAAP) (GAAP Net Income) - (b) / (f)	**17.1%**	**-8.1%**	**-29.5%**	**17.6%**	
ROE (Non-GAAP) (Non-GAAP Adjusted Net Income) - (c) / (g)	**4.6%**	**-6.6%**	**0.2%**	**16.4%**	

* Average for the current and immediately preceding year

Adjustments to Net Income (Loss) (GAAP)

(a) See below schedule for detail of adjustments to Net Income (Loss) (GAAP) in 2017:

	Year Ended December 31, 2017		
	Before Tax	Income Tax Impact	After Tax
Adjustments:			
Add: Mark-to-Market Commodity Derivative Contracts Impact	$ (12)	$ 4	$ (8)
Add: Impairments of Certain Assets	261	(93)	168
Add: Net Losses on Asset Dispositions	99	(35)	64
Add: Legal Settlement - Early Lease Termination	10	(4)	6
Add: Joint Venture Transaction Costs	3	(1)	2
Add: Joint Interest Billings Deemed Uncollectible	5	(2)	3
Less: Tax Reform Impact	-	(2,169)	(2,169)
Total	$ 366	$ (2,300)	$ (1,934)

(b) See below schedule for detail of adjustments to Net Income (Loss) (GAAP) in 2016:

	Year Ended December 31, 2016		
	Before Tax	Income Tax Impact	After Tax
Adjustments:			
Add: Mark-to-Market Commodity Derivative Contracts Impact	$ 77	$ (28)	$ 49
Add: Impairments of Certain Assets	321	(113)	208
Less: Net Gains on Asset Dispositions	(206)	62	(144)
Add: Trinidad Tax Settlement	-	43	43
Add: Voluntary Retirement Expense	42	(15)	27
Add: Acquisition - State Apportionment Change	-	16	16
Add: Acquisition Costs	5	-	5
Total	$ 239	$ (35)	$ 204

(c) See below schedule for detail of adjustments to Net Income (Loss) (GAAP) in 2015:

	Year Ended December 31, 2015		
	Before Tax	Income Tax Impact	After Tax
Adjustments:			
Add: Mark-to-Market Commodity Derivative Contracts Impact	$ 668	$ (238)	$ 430
Add: Impairments of Certain Assets	6,308	(2,183)	4,125
Less: Texas Margin Tax Rate Reduction	-	(20)	(20)
Add: Legal Settlement - Early Leasehold Termination	19	(6)	13
Add: Severance Costs	9	(3)	6
Add: Net Losses on Asset Dispositions	9	(4)	5
Total	$ 7,013	$ (2,454)	$ 4,559

(d) See below schedule for detail of adjustments to Net Income (Loss) (GAAP) in 2014:

	Year Ended December 31, 2014		
	Before Tax	Income Tax Impact	After Tax
Adjustments:			
Less: Mark-to-Market Commodity Derivative Contracts Impact	$ (800)	$ 285	$ (515)
Add: Impairments of Certain Assets	824	(271)	553
Less: Net Gains on Asset Dispositions	(508)	21	(487)
Add: Tax Expense Related to the Repatriation of Accumulated Foreign Earnings in Future Years	-	250	250
Total	$ (484)	$ 285	$ (199)

EOG RESOURCES, INC.

Quantitative Reconciliation of After-Tax Net Interest Expense (Non-GAAP), Net Debt (Non-GAAP) and Total Capitalization (Non-GAAP) As used in the Calculation of Return on Capital Employed (Non-GAAP) to Net Interest Expense (GAAP), Current and Long-Term Debt (GAAP) and Total Capitalization (GAAP), Respectively

(Unaudited; in millions, except ratio data)

The following chart reconciles Net Interest Expense (GAAP), Current and Long-Term Debt (GAAP) and Total Capitalization (GAAP) to After-Tax Net Interest Expense (Non-GAAP), Net Debt (Non-GAAP) and Total Capitalization (Non-GAAP), respectively, as used in the Return on Capital Employed (ROCE) (Non-GAAP) calculation. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who utilize After-Tax Net Interest Expense, Net Debt and Total Capitalization (Non-GAAP) in their ROCE calculation. EOG management uses this information for purposes of comparing its financial performance with the financial performance of other companies in the industry.

	2013	2012	2011	2010	2009	2008	2007	2006	2005
Return on Capital Employed (ROCE) (Non-GAAP) (Calculated Using GAAP Net Income)									
Net Interest Expense (GAAP)	$ 235	$ 214	$ 210	$ 130	$ 101	$ 52	$ 47	$ 43	$ 63
Tax Benefit Imputed (based on 35%)	(82)	(75)	(74)	(46)	(35)	(18)	(16)	(15)	(22)
After-Tax Net Interest Expense (Non-GAAP) - (a)	$ 153	$ 139	$ 137	$ 85	$ 66	$ 34	$ 31	$ 28	$ 41
Net Income (Loss) (GAAP) - (b)	$ 2,197	$ 570	$ 1,091	$ 161	$ 547	$ 2,437	$ 1,090	$ 1,300	$ 1,260
Total Stockholders' Equity (GAAP) - (d)	$ 15,418	$ 13,285	$ 12,641	$ 10,232	$ 9,998	$ 9,015	$ 6,990	$ 5,600	$ 4,316
Average Total Stockholders' Equity (GAAP) * - (f)	$ 14,352	$ 12,963	$ 11,437	$ 10,115	$ 9,507	$ 8,003	$ 6,295	$ 4,958	$ 3,631
Current and Long-Term Debt (GAAP) - (h)	$ 5,909	$ 6,312	$ 5,009	$ 5,223	$ 2,797	$ 1,897	$ 1,185	$ 733	$ 985
Less: Cash	(1,318)	(876)	(616)	(789)	(686)	(331)	(54)	(218)	(644)
Net Debt (Non-GAAP) - (i)	$ 4,591	$ 5,436	$ 4,393	$ 4,434	$ 2,111	$ 1,566	$ 1,131	$ 515	$ 341
Total Capitalization (GAAP) - (d) + (h)	$ 21,327	$ 19,597	$ 17,650	$ 15,455	$ 12,795	$ 10,912	$ 8,175	$ 6,333	$ 5,301
Total Capitalization (Non-GAAP) - (d) + (i)	$ 20,009	$ 18,721	$ 17,034	$ 14,666	$ 12,109	$ 10,581	$ 8,121	$ 6,115	$ 4,657
Average Total Capitalization (Non-GAAP) * - (j)	$ 19,365	$ 17,878	$ 15,850	$ 13,388	$ 11,345	$ 9,351	$ 7,118	$ 5,386	$ 4,330
ROCE (GAAP Net Income) - [(a) + (b)] / (j)	**12.1%**	**4.0%**	**7.7%**	**1.8%**	**5.4%**	**26.4%**	**15.7%**	**24.7%**	**30.0%**
Return on Equity (ROE) (GAAP)									
ROE (GAAP Net Income) - (b) / (f)	**15.3%**	**4.4%**	**9.5%**	**1.6%**	**5.8%**	**30.5%**	**17.3%**	**26.2%**	**34.7%**

* Average for the current and immediately preceding year

EOG RESOURCES, INC.

Quantitative Reconciliation of After-Tax Net Interest Expense (Non-GAAP), Net Debt (Non-GAAP) and Total Capitalization (Non-GAAP)
As used in the Calculation of Return on Capital Employed (Non-GAAP) to Net Interest Expense (GAAP),
Current and Long-Term Debt (GAAP) and Total Capitalization (GAAP), Respectively
(Unaudited; in millions, except ratio data)

The following chart reconciles Net Interest Expense (GAAP), Current and Long-Term Debt (GAAP) and Total Capitalization (GAAP) to After-Tax Net Interest Expense (Non-GAAP), Net Debt (Non-GAAP) and Total Capitalization (Non-GAAP), respectively, as used in the Return on Capital Employed (ROCE) (Non-GAAP) calculation. EOG believes this presentation may be useful to investors who follow the practice of some industry analysts who utilize After-Tax Net Interest Expense, Net Debt and Total Capitalization (Non-GAAP) in their ROCE calculation. EOG management uses this information for purposes of comparing its financial performance with the financial performance of other companies in the industry.

	2004	2003	2002	2001	2000	1999	1998	1997
Return on Capital Employed (ROCE) (Non-GAAP) (Calculated Using GAAP Net Income)								
Net Interest Expense (GAAP)	$ 63	$ 59	$ 60	$ 45	$ 61	$ 62	$ 49	
Tax Benefit Imputed (based on 35%)	(22)	(21)	(21)	(16)	(21)	(22)	(17)	
After-Tax Net Interest Expense (Non-GAAP) - (a)	$ 41	$ 38	$ 39	$ 29	$ 40	$ 40	$ 32	
Net Income (Loss) (GAAP) - (b)	$ 625	$ 430	$ 87	$ 399	$ 397	$ 569	$ 56	
Total Stockholders' Equity (GAAP)- (d)	$ 2,945	$ 2,223	$ 1,672	$ 1,643	$ 1,381	$ 1,130	$ 1,280	$ 1,281
Average Total Stockholders' Equity (GAAP) * - (f)	$ 2,584	$ 1,948	$ 1,658	$ 1,512	$ 1,256	$ 1,205	$ 1,281	
Current and Long-Term Debt (GAAP) - (h)	$ 1,078	$ 1,109	$ 1,145	$ 856	$ 859	$ 990	$ 1,143	$ 745
Less: Cash	(21)	(4)	(10)	(3)	(20)	(25)	(6)	(9)
Net Debt (Non-GAAP) - (i)	$ 1,057	$ 1,105	$ 1,135	$ 853	$ 839	$ 965	$ 1,137	$ 736
Total Capitalization (GAAP) - (d) + (h)	$ 4,023	$ 3,332	$ 2,817	$ 2,499	$ 2,240	$ 2,120	$ 2,423	$ 2,026
Total Capitalization (Non-GAAP) - (d) + (i)	$ 4,002	$ 3,328	$ 2,807	$ 2,496	$ 2,220	$ 2,095	$ 2,417	$ 2,017
Average Total Capitalization (Non-GAAP) * - (j)	$ 3,665	$ 3,068	$ 2,652	$ 2,358	$ 2,158	$ 2,256	$ 2,217	
ROCE (GAAP Net Income) - [(a) + (b)] / (j)	**18.2%**	**15.3%**	**4.8%**	**18.2%**	**20.2%**	**27.0%**	**4.0%**	
Return on Equity (ROE) (GAAP)								
ROE (GAAP Net Income) - (b) / (f)	**24.2%**	**22.1%**	**5.2%**	**26.4%**	**31.6%**	**47.2%**	**4.4%**	

* Average for the current and immediately preceding year

OFFICERS AND DIRECTORS

(As of February 27, 2018)

Directors

Janet F. Clark (1)
Houston, Texas
Retired Executive Vice President and
Chief Financial Officer,
Marathon Oil Corporation

Charles R. Crisp (2)
Houston, Texas
Investments

Robert P. Daniels (3)
The Woodlands, Texas
Retired Executive Vice President,
International and Deepwater Exploration,
Anadarko Petroleum Corporation

James C. Day (4)
Sugar Land, Texas
Retired Chairman of the Board and
Chief Executive Officer,
Noble Corporation

C. Christopher Gaut (3)
Houston, Texas
Chairman of the Board (Non-Executive),
Forum Energy Technologies, Inc.

Donald F. Textor (3)
Locust Valley, New York
Portfolio Manager, Dorset Energy Fund

William R. Thomas
Chairman of the Board and
Chief Executive Officer,
EOG Resources, Inc.

Frank G. Wisner (5)
New York, New York
International Affairs Advisor,
Squire Patton Boggs

Officers
(including key subsidiaries)

William R. Thomas
Chairman of the Board and
Chief Executive Officer

Gary L. Thomas
President

Lloyd W. Helms, Jr.
Chief Operating Officer

David W. Trice
Executive Vice President,
Exploration and Production

Ezra Y. Yacob
Executive Vice President,
Exploration and Production

Timothy K. Driggers
Executive Vice President and
Chief Financial Officer

Michael P. Donaldson
Executive Vice President, General Counsel and
Corporate Secretary

Sandeep Bhakhri
Senior Vice President and
Chief Information and Technology Officer

John J. Boyd, III
Senior Vice President, Operations

Patricia L. Edwards
Senior Vice President and
Chief Human Resources Officer

Ann D. Janssen
Senior Vice President and
Chief Accounting Officer

D. Lance Terveen
Senior Vice President, Marketing

Nathan J. Andrews
Vice President and General Manager,
Oklahoma City

Kenneth W. Boedeker
Vice President and General Manager,
Denver

Eric A. Dillé
Vice President, Government Relations

Kenneth E. Dunn
Vice President and General Manager,
Fort Worth

Marc R. Eschenburg
Vice President, Marketing Services

Nicholas J. Groves
Vice President, Safety and Environmental

Kevin S. Hanzel
Vice President, Audit

Joseph L. Korenek
Vice President, Business Development

Reese T. Lantrip
Vice President and General Manager,
Artesia

Jeffrey R. Leitzell
Vice President and General Manager, Midland

Kenneth D. Marbach
Vice President and General Manager,
Corpus Christi

Jill R. Miller
Vice President, Engineering and Acquisitions

Richard A. Ott
Vice President, Tax

Sammy G. Pickering
Vice President and General Manager,
San Antonio

Charles E. Sheppard
Vice President, Exploration

Robert C. Smith
Vice President, Drilling

David J. Streit
Vice President, Investor and Public Relations

Steven D. Wentworth
Vice President, Land

Robert L. West
Vice President and Treasurer

J. Pat Woods
Vice President and General Manager,
International

James C. Fletcher
Controller, Land Administration

Joseph C. Landry
Controller, Operations Accounting

Gary Y. Peng
Controller, Financial Reporting

Amos J. Oelking, III
Deputy Corporate Secretary

(1) Chairperson, Audit Committee; Member, Compensation and Nominating and Governance Committees

(2) Member, Audit, Compensation and Nominating and Governance Committees; 2018 Presiding Director

(3) Member, Audit, Compensation and Nominating and Governance Committees

(4) Chairman, Compensation Committee; Member, Audit and Nominating and Governance Committees

(5) Chairman, Nominating and Governance Committee; Member, Audit and Compensation Committees

STOCKHOLDER INFORMATION

Corporate Headquarters
1111 Bagby, Sky Lobby 2
Houston, Texas 77002
P.O. Box 4362
Houston, Texas 77210-4362
(713) 651-7000
Toll Free: (877) 363-EOGR (363-3647)
www.eogresources.com

Common Stock Exchange Listing
New York Stock Exchange
Ticker Symbol: EOG
Common Stock Outstanding at December 31, 2017: 578,476,807 shares

Transfer Agent
Computershare Trust Company, N.A.
Attn: Shareholder Services
P.O. Box 505000
Louisville, KY 40233-5000
Toll Free: (877) 282-1168
Outside U.S.: (781) 575-2879
www.computershare.com
Hearing Impaired: TDD (800) 952-9245

2018 Annual Meeting of Stockholders

EOG's 2018 Annual Meeting of Stockholders will be held at 2 p.m., Central Daylight Time, at Heritage Plaza, Plaza Conference Room, Plaza Level, 1111 Bagby Street, Houston, Texas, on Tuesday, April 24, 2018. Information with respect to the annual meeting is contained in the proxy statement made available with this Annual Report to holders of record of EOG Common Stock as of February 27, 2018. This Annual Report is not to be considered a part of EOG's proxy soliciting material for the annual meeting.

Certifications

In 2017, EOG's Chief Executive Officer (CEO) provided to the New York Stock Exchange (NYSE) the annual CEO certification regarding EOG's compliance with the NYSE's corporate governance listing standards. In addition, EOG's CEO (principal executive officer) and EOG's principal financial officer filed with the United States Securities and Exchange Commission (SEC) all certifications required in EOG's SEC reports for fiscal year 2017.

Additional Information

Additional copies of this Annual Report (as well as copies of any of the exhibits to the Form 10-K included herein) are available upon request by calling (877) 363-EOGR (363-3647); by writing EOG's Corporate Secretary (Michael P. Donaldson) at EOG Resources, Inc., 1111 Bagby, Sky Lobby 2, Houston, Texas 77002; or by visiting the EOG website at www.eogresources.com. Quarterly and annual earnings press release information for EOG and EOG's SEC filings also can be accessed through EOG's website.

Financial analysts and investors who need additional information should visit the EOG website at www.eogresources.com or contact EOG's Investor Relations department at (713) 651-7000.

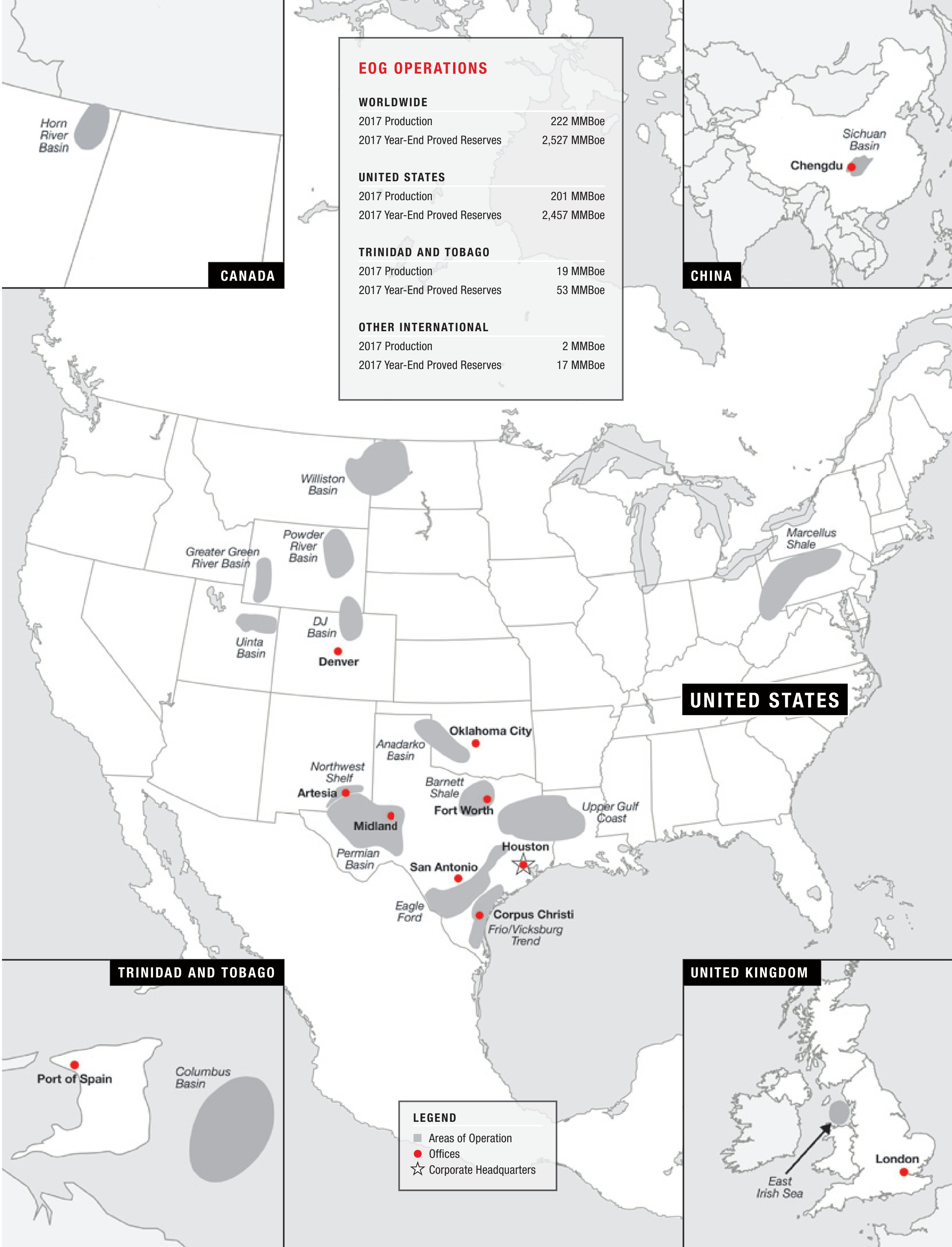
OUR EMPLOYEES

Ahmed Abdullah Renesha Abraham Gus Abrahamson Linda Abrego Turk Ackerman David Ackman Aron Acosta Ed Acosta Linda Acosta Gabby Adame Cheryl Adams Jeffrey Adams Nelda Adams Skylar Addicks Rhonda Addison Jeremy Adrian Mike Adrion Amer Afifi Bobbie Aguilar Candy Aguilar Amit Ahuja Blaine Akin Shane Akin Shanthi Akki Akkisetty Melissa Albert Alex Albertoni Marisol Albino Wilson Myrna Albright Jennifer Alcocer Mahdee Aleem Cesar Aleman Aaron Alexander Anthony Alexander Kerry-Ann Alexander Patrick Alexander Shalonda Alexander Travis Alexander Meshal Al-Khabbaz Raymond Allbee Ken Allemand Jennifer Allen Scott Allison Stephanie Allman Evan Allred Richard Alonso Derek Alquist Kim Alvarado Dan Ambuehl Junior Andall Aaron Anderson Brian Anderson Cathy Anderson Charlie Anderson Jeremy Anderson Karen Anderson Landon Anderson Nayely Anderson Rene Anderson Scott Anderson Levi Andreas Frances Andreassen Nathan Andrews Kathrine Angyal-Waddy Jim Anschutz Osman Apaydin Sandra Apodaca Fernanda Araujo John Archambault Ali Ardington Carlos Arevalo Mario Arevalo Alex Argueta Erin Arkison Joshua Armentrout Shonna Armstrong Cora Arnall Cody Arnold Artie Arredondo Edgar Arreola Andrea Arrey Jared Arrey Monica Arrey Jayanthi Arya Bob Asher Chelsea Ashworth Joe Aston Darrell Atkins Haritha Atluri Lizz Atnafu Carlotta Audain Dan Auld Jason Aultman Damon Austin Richard Austin Daubie Autry Orlando Ayala Wale Ayoola Sanaa Azeez Shelly Babcock Darla Baccus David Baccus Krishna Bachan Scott Backer Brian Bacon Dewayne Baethge Krystina Baez Colby Baggs Bryan Bahr Dave Bailey Diane Bailey Dustin Bailey John Bailey Michael Bailey Mike Bailey Steve Bailey Peter Bair Jamie Baird Andy Baker Kevin Baker Lanny Baker Neal Baker Eric Balderaz Bryan Baldwin Lorraine Baline Hunter Ball Gloria Ballin Kyle Bangert Valeria Banks Brian Baptiste Kristian Baptiste Linda Barberousse Jared Barden Tarra Barker Kelley Barnett Aaron Baros Andrew Barrera Hector Barrera Jennifer Barrera Mitzi Barrera Loren Barrett German Barrientos Keith Bartenhagen Amanda Bartlett Blain Barton James Barwis Charles Bassett Whittney Bates Mary Ann Batie JR Baughman Crystal Baxter Heather Bayless Kevin Beahan Maggie Bean Rene Beck Italo Beckles Brock Begg Larry Beiland Rene Bela Richard Belasquez Ray Belcher Rachel Belk Chris Bell Heath Bell Dennis Bellows Cory Benes Tammy Benishek Kristy Bennett Tana Bennett Gust Benninger Andrew Bentley Bryce Berg Shane Berg Vickie Bernal Martha Bernardini Alex Bernhard Ty Bernhard Caroline Bertuzzi Brad Betsworth Dmytro Bevzenko Sandeep Bhakhri Noah Bianchi Ilyn Bielamowicz Bennie Biery Sam Biffle Dylan Bigbie Nacole Biggers Justin Biggs Tammy Billington Albert Billman Bobby Bingham Ryan Bingham Aaron Bishop Mindy Black John Blackburn Randall Blackburn Ryan Blackburn Katy Blackman Ben Blackwelder Zeco Blair Lonnie Blake Sibyl Blankenship Sara Blatnick Justin Blau Stephanie Bleich Dana Blevins Tracy Blome Johnnie Blount Jon Bocox Ken Boedeker Jarrid Boehm Jason Bohm Dave Bokor Jordan Boland Paul Boland Arabella Bolanos Wade Bolting Kylie Bolton Wendy Bone Christy Bonetti Laramie Bonham Kent Boomhower Alisa Booth Vera Boren Kyle Borrello Cody Bouler Tyson Bouler Laura Bourgeois Deidra Bourland Heather Bourland Kyle Bowen Terri Bowen Marcus Bowlin Ashley Bowman Kyle Bowzer John Boyd Stephen Boyer Bruce Brannan Brett Brasher Bethany Braune Katy Braune Ashley Bravo Steve Bray Randall Bridges Jolene Brittain Carlene Britton-Carrington Amanda Brock Jason Brogdon Daniel Brokaw Brett Bromwell Bill Brooks Michael Brooks Myron Brooks Sammy Brooks Jack Brophy Kevin Brophy Brandon Brown Carola Brown Chris Brown Chris Brown Derek Brown Dillon Brown Glen Brown Jeff Brown Jessica Brown Kenneth Brown Marty Brown Natalie Brown Steven Brown Bruce Brumley Lance Brumley Josie Brunick Linda Bruster Young Clay Bryan Dwayne Bryan Kacktus Bryan James Buchholtz Greg Buckner Roman Budinskiy Dane Buendel Jaime Bueno Steve Bugni Denise Bullard Evan Bullard John Bullard Matthew Buoniconti Fayetta Burch Darryl Burger Rick Burke James Burkett Eric Burkholder Jennifer Burris Shaun Burris Jim Burrows Bennett Burt Doug Burt Laurie Burt Rick Burton Sandra Burton Victoria Bush Rose Mary Bussell Tim Bussell Oscar Bustos Brandy Butler Dennis Butler Lance Butler Salman Butt Wade Buxcel Brant Buzbee Janice Byam Russell Byers Dustin Bynum Christina Byrom Noe Cadena Ronnie Cafagna Sheila Cahalane Min Cai Steven Cain Jared Calder Chris Caldwell Ingrid Callender Robby Callicotte Howdy Cameron Dennis Camino Billy Campbell Cathy Campbell Chad Campbell Dave Campbell Nick Canava Steve Canion Mike Cannon Concha Cano Kenny Cantrell Randy Cao Nick Caporale Emmett Capt Pedro Capuchin Lindsay Caram John Cardin Sam Cardona Mike Carey Steven Carle Patti Carlile Skip Carnes Ronnie Carney James Carpenter Luke Carpenter Hiram Carpio Cary Carrabine Allison Carrasco Darin Carrasco Bob Carroll Phil Carroll Kathy Carten Christopher Carter Misty Carter Paul Carter David Carver Jake Carver Brandi Casanova Simon Casas Rachel Casillas Dereck Casimir Cathy Castaneda Nick Castaneda Josh Castillo Rebecca Castro-Lowe Nina Catalucci Darrell Catchings Jason Cates Kent Caudle Suzette Cavazos Jonathan Cave Teresa Cazares Monita Cebell Casey Center Daniel Cervantes Keith Cervantes Mike Cervantes Ian Cervi Ethan Chabora Sergio Chacon David Chadwick Brenda Chambless Brian Chandler John Chapman Korrey Charboneau Albert Charles Kathy Ann Charles Narvin Charles Jeannette Charles-Martinez Travis Charnetzki Anish Chaudhary Regina Chavarria Monica Chaves Barbarita Chavez Debbie Chavez Joe Chavez Laura Chavez Sheila Chavez Perry Chen Tom Chen William Chesnut Jacob Chew Deborah Childress Shawn Childs Janice Chin-Wing Drayton Andrew Chodur Tracey Chong-Ashing Bev Christensen Marcus Chroback Natalia Chukhontceva Kamal Chunilal Bert Clark Gregory Clark Jared Clark John Clark Keith Clark Terence Clarke Timothy Clarke Chatham Clary Michelle Clary Stephen Claycamp Davro Clements Baron Clifford Jeannie Cluiss Colton Cobb Crystal Cobb Tish Cobb Susan Cockerham Ben Cockrill Sherron Codogan Donna Coe Bruce Coit Cheryl Coker Kurt Coldewey Allen Coldewey Jr. Craig Cole Allen Coleman Bradley Coleman Carolyn Coleman Clay Coleman Jeremy Coleman Chuck Collier Calvin Collins David Collins Vicki Collins Chuck Colson Matt Conklin Stevan Contreras Duane Cook Evan Cook Lisa Cook RL Cook Tyler Coon Christina Coons Ruchira Corey Trent Corkran Neal Cormier Cooper Cornelius Jacob Corpron Paul Corrales Javier Cortesia Scott Costner Josh Cotter Pam Cotton Damon Cottrell Stephen Couch Heather Couchman David Counce Yvette Counts Richard Couture Leon Covell III Alan Covington Jordan Cowan Clinton Cox Greg Cox Justin Cox Mark Cox Shawn Cox Tyler Cox Andrew Coxon Jack Craddock Bette Cranford Kimberly Crapo Cody Cravens Janice Cravens Bobbie Crawford George Crawshaw Misti Creach Teresa Criddle Cody Crites Chris Crocker Sandy Cromer Stacie Crosby Christopher Crow Barry Crowder Herminia Cruz Megan Cruz Wade Cuch Chris Culver Adam Cumbie Dileon Cummings Jim Cunkelman Casey Curd Terri Currie Edwin Custodio AJ Dach Jesse Daggett Brian Dahl Joshua Dahly Qi Dai Vivian Dai Michael Daigle Todd Dalessandro Todd Dalton Wendy Dalton Joey Damiano Barry Dampman Gary Danks Marsha Danzell Judy Dargin Jeremiah Darr Whitney Darr Loni Daub Samantha Davila Dave Davis Dustin Davis Gina Davis Larry Davis Matt Davis Matthew Davis Michael Davis Samantha Davis Stephen Davis Trevor Davis Andrew Dawson Kevin Dawson Matt Day Portia De Four Nick De Leon Tricia De Souza Cameron Dean Andrew Deane Sherri DeBakey Kim Dechaud Joe Decker Mike Decker Juan Del Rio Terry Del Rio Jennifer Del Tatto Daisy Del Val Olga DeLand Steve DeLand James DelCampo Joseph DelCampo Denise Delgado Jeanette Delgado Brenda Dellinger Tyler Denham Jim Denman DaLina Dennis Davis DeSautel Kyle DeTienne Nivid Dholakia Otto Dick Debbie Dickey Stuart Dickson Casey Dietz Lauren Dietzel Jeff Diffely JP Dillard Nikki Dillard Eric Dille Trudy Dillon Liesel Dionisio Nathan Dirks Mark Dixon Trevor Dobbs Annette Dobson Jonathan Dodd Corbin Doffer Georgeanne Dollar James Dominguez Manuel Dominguez Kathy Donaldson Michael Donaldson James Donnelly Marshall Doolittle Matt Dotin Anita Douglas Eric Douglas Jackie Douglass Frank Dowell Barbara Downs Larraine Drake Joel Draper Tim Driggers Dannon Drosdal John Dubose Kevin Duff Zac Duff Cindy Duge Stephen Duke Trixy Duke Shannon Dumolt Daniel Dunaway Ken Dunn Ashley Dupont George Dupre Darwood Dupree Doug Durand Hannah Durkee Robbey Dutton Richard Dvarishkis Tell Dyer Eric Dyke Dane Eccles Stacey Eddings Randall Edgeman Madeline Edgley Josh Edwards Michael Edwards Pat Edwards Danielle Edwards-Dupay Kurt Eggebrecht Clint Egger Kimberly Ehmer Clay Eldred Gary Eldred Judy Elizalde Keith Elliott Ashley Ellis Kathy Ellis Ryan Ellis Scott Ellis Casey Ellison Dirk Ellyson Thomas Elmer Jeffrey Elsworth Courtney Emerson Shawn Engberg Chris Enger Brandon Englert Kelsey Enke Alan Ennis Silvia Enriquez Colton Epps Duane Ervin Marc Eschenburg Doug Esmond Amanda Espinosa Jaime Espinosa Connie Esquibel Victor Esquibel Marcus Estes Sandra Estrada Alvaro Estrello Joe Estvold Jeremiah Eubank Mark Evanoka Ed Evans Joe Evans Steven Evans Russell Evatt Riker Everett Christopher Ezell Christine Fallon Matthew Fare Logan Farmar Naomi Farmer Ryan Farquhar Brandon Farrar Klint Farrar Mike Farris Ryann Farris Adam Farrow Samad Fassihi Eileen Faulk Shelley Fellenstein Chelse Felts Chris Ferguson Len Ferguson Samantha Fernandez Shawn Filcaske Scott Filz Clayton Fisher Judy Fisher Craig Flatt Michael Flax Julie Fleetwood Jason Fleniken Amber Fletcher James Fletcher Marty Fletcher Sherry Fletcher Corey Flick Mitchel Flick Delilah Flores Nicolas Flores Nicole Flores Sonia Florez Chip Fly Tristen Folden David Follingstad Kirk Foreman Larry Formo JJ Forrest Kenny Forrester Adam Fossett Brice Foster Jon Foster Kenneth Fougerat Andrew Foulkes Meredith Fowler Dan Fox Nancy Franco Chris Frank Chad Frederick Danny Frederick Denise Frederick Donald Frederick Jason Frederick Rickey Frederick Jamey Fredrickson David Freeland Brian Freeman Jacob Freeman John Freeman Kevin Fretheim Richard Frith Lee Frost Joel Fuentes Juan Fuentes Laura Fuentes Marcela Fuentes Matt Fuller Jonathan Funk Tim Fusselman Paige Futrell Jared Gabro Sarah Gach Mason Gadberry Johnny Gaines Iliana Galan Ricky Galan Ademar Galvan Roy Galvan Vicente Galvan Gregory Gammage Chelsea Gamron Ryan Ganaway Shabbir Gandhi Aaron Gandrud Jamie Gandrud Kapil Gangapersad Nathan Gann Paul Garafalo Peter Garbee Paul Garber Nancy Garcia Sergio Garcia Tony Garcia Reggie Garcille Cody Gardiner Chris Gardner David Gardner Michael Gardner Dwayne Garnett Riley Garrison Tom Garrison Angela Garza Herman Garza Joseph Garza Patsy Garza Matt Gastgeb Ryan Gauthier Lori Geiger Greg Geis Jared Geis Dennis Gensman Ginny Gent Nic Gergen Charlie Gibson Derrick Gibson Elaine Gibson Mark Gibson Jeff Gigstad Doug Gilbertson Carrie Gilchrist Mason Gill Randy Gillo Christine Gilmore Evan Gilmore John Gilmore Yvonne Gilmore JP Gips Amy Gipson Jim Giuliani Elmo Glover Rowdy Glover Michele Godsey Neelima Godugu Garrett Goebel Adam Goff Anelia Gogova Jeff Goldberg Curtis Golde Esmeralda Golden Adam Goldsmith Gregg Gomez Juan Gomez Noel Gomez Derek Gonet Charles Gonzales Patrick Gonzales Sam Gonzales Evan Gonzalez Juanita Gonzalez Rick Gonzalez Clint Goodman Gordon Goodman Surendar Gopinath Joe Gordon Joe Gordon Steve Gordon Lynnette Goshorn Lisa Gosine-Alleyne Kevin Gottschall Steven Gottwald Hillari Gould Aaron Gourneau Terry Gowers Amy Graham Andrew Graham Bridgette Graham Gene Grant Gordon Grant Michael Grant Morgan Grant Dewayne Gray Donald Gray Dortha Gray Dustin Gray Jim Gray Joshua Gray Katherine Gray Marc Gray Matthew Gray Mitch Gray Pam Gray Blake Green Bryan Green Jayne Green Karen Greengrass Enoch Greenhood Amber Griffin Red Griffin Mark Griggs Dallen Grimes Stan Grimes Chelsea Grimm Isaac Griner Barb Griswold Wayne Groo Thera Grosshans Matt Groves Nick Groves Judy Guebara Christopher Guenthner Carlos Guerrero Joey Guerrero Evelyn Guess Roshend Guevara Christor Guidry John Guillot Tyler Guinn Shelly Gummelt Kevin Gunder Britnye Gurule Chris Gurule Gerard Gustilo Shaun Guthrie Blair Haaland Jeremy Haass Tracy Haenfler Kristin Hagebak Clay Haggard Ashley Hahn Alex Hale Durk Hall Josh Hall PJ Hall Ted Hall Rhett Halverson Rodney Halvorson Matt Hamilton Todd Hamilton Wayne Hamilton Rob Hamlet Le Hammer Brian Hampton Debbie Hamre Jamie Hanafy Kirk Hanberg Paul Hanes Cynthia Hanselman Susan Hanselman DJ Hansmann Kevin Hanzel Ryan Harbor Ricky Hardaway Badia Hardin Nancy Harding Bart Hardman Lindsey Hardouin Barbara Hargis David Hargrave Sean Harlan Jeff Harmon Sharon Harmon Sam Harms Allen Harp Isabel Harper John Harper Thomas Harrington Daniel Harris Deana Harris Kristy Harris Matt Harris Nathan Harris Pamela Harrison Spencer Harrison Clint Harry Ariel Hart Kara Hart Dennis Hartwig Lauren Harwell Lee Hastings Mark Hately Tammy Hatfield Dale Hathaway Meredith Hatz Michele Hatz Gina Hauck Allison Hawkins Jennifer Hawkins Joeann Hayes Jerry Haynes Haiden Hayward Britt Hazelbush Yong He Scott Head Brandon Headrick Thomas Hearon Nathan Hedge Shane Heidel Mike Heil Mitchell Heimer Jonathan Helm Blake Helmke Billy Helms Cory Helms James Henderson Cody Hendricks Gina Henley Rose Henley Dustin Henline Jim Henning Christopher Heny Cory Hepburn Dominique Hepburn Wade Hermanson Floyd Hernandez Jorge Hernandez Laura Hernandez Price Hernandez Raul Hernandez Rosie Hernandez Susan Herpin Lupe Herrera Justin Herring Michael Herrington Greg Hersperger Jake Hervey Jenna Hessert Billy Hester Luigi Heydt Mike Heymann Jimmy Hickman Michael Hickman Jade Hicks Justin Hicks Mickey Hicks Vicki Hietpas Casey Hilbig Acie Hill Brandon Hill Brian Hill Clay Hill Darius Hill Garrett Hill Karen Hill Mike Hill Ronald Hill Steve Himes Matthew Hinkle Rob Hinnant Luke Hise Linda Hoang Clare Hobday Chad Hodge Jeff Hodge Cecil Hodges Kenneth Hodges Randy Hodgins Chris Hoefer Tanner Hoelscher Robyn Hofer Darby Hoffman Dusty Hoffman Jessica Hoffman Jim Hoffman Brenna Hogarth Jamon Hohensee Bass Hohertz Derek Holeman Bryan Holgate Danny Holgate Jared Holgate Daniel Holguin Brian Holland KC Holland Nathan Hollek Joel Holleman Glede Holman Alec Holmes Braden Holmes Brant Holmes Derrik Holmes Eric Holmes Angie Holt Dillon Holt Jon Holt Wayne Holt Shay Holte Rhonda Holtgreive Erich Holzer Heather Hong Blake Hopkins Ashraful Hoque Garland Horak Mike Horgan Stacy Horn Kane Horner Brett Horton Helen Hosein-Mulloon Joanna Hoss Margrethe Hotter Haley Hough Natalie Houlihan Dexter Hoverson Rick Hovland Gloria Howard Kit Howard Jeffrey Howe Linda Howerton Andy Hoyle Aisha Hozri Jack Huang Sean Huang Courtney Hubbard Michael Hubbard Bob Hubbert Brandy Hudson Tina Huerta Angel Huezo Colton Huggins Cas Hughes Tammy Hughes Cynthia Hui Shawn Hummel John Humphrey Robert Humphreys Wan-Hsiang Hung Jeremy Hunt Kermal Hunt Patty Hunt Keron Hunte Kellen Hunter Cindy Hur Vue Owen Hurd Judith Hurt Keith Hutchens Michael Hutchings Brian Hysjulien Silvia Iglesias Jack Imboden Laurie Infante Lindsey Ingle Ryan Ingle Scott Ingle Mikayla Inlow Mike Isaacs Tarik Itibrout Allan Itz Kelley Ivanova Ash Iverson Alex Ives Sarah Ivey Jacob Ivie Buster Ivory Yvonne Iwo-Brown Bubba Jackson Jeffery Jackson L.J. Jackson Melinda Jackson Mike Jackson Shelby Jackson James Jacob Jeff Jacobson Chris James Jordan James Susan James Ann Janssen Darryl Janssen Jill Janssen Tracey Jarmin Jennifer Jarvis Wayne Jefferson Camille Jenman Tammi Jensch Ryan Jensen Terri Jimenez Yvonne Jimenez Ling Jin Traci Jiral Shahid Jivani Gurya Jiwani Benjamin Johnson Bryan Johnson Carolyn Johnson Corby Johnson Daniel Johnson Denis Johnson Derek Johnson Jay Johnson Jedidiah Johnson Jessica Johnson John Johnson Kayla Johnson Keith Johnson Martin Johnson Matt Johnson Robert Johnson Steve Johnson Chrystine Johnson Arellano David Johnston Alex Jones Chris Jones Edward Jones Emile Jones Jared Jones Jeremiah Jones Joy Jones Kayla Jones Peter Jones Ray Jones Sherry Jones Zack Jones Casey Jones-Peterson Michael Jordan Jon Jorgenson Ricky Joyce Davey Juarez Joe Justus Ross Kalous Ron Kane Shayena Kanju Teresa Kaplan Ammar Karachiwala Chetan Karanth Shane Karhoff Matt Karls Josh Karren Candace Kaspar Tom Kastens Janene Kauffman Chance Kay Mark Kay Jill Kean Jim Keenan Branden Keener James Keeton Lex Keim Chad Keller Edgar Keller Brendan Kelly Shane Kelly Steven Kelly Ted Kelly Duane Kendall John Kennah Brandon Kennedy Bryce Kennedy Chris Kennedy Claresia Kennedy Jennifer Kennedy Steve Kennedy Tammy Kennedy Ronald Kenny Kyle Keplin Sean Kessel Paul Kessler Pratik Kharel Mimi Khatiyavong Alex Khorram Roni Kidd Bob Kidney Colin Kiernan Kristen Kifer Michael Kilen George Killmer Spencer Kimball Billy Kimbro Ashley Kinder Dustin Kinder Efrem King Mark King Richard King Robert Kinnoin Jodi Kipp Jeff Kippen Nan Kippen Andrew Kircher Chris Kirgan Amanda Kirkham Carol Kirksey Colt Kissling Jim Klein Susan Klein Julie Klepac Adam Kline Jennifer Knickerbocker David Knier Gerald Knight Ron Knippa Randy Koehler Kelly Koehn Everett Koelling Amanda Koenning Anthony Koester Greg Kohlhof David Kondret Eric Koppinger Joe Korenek David Kos Bob Kosa Alan Kothmann Daniel Koury Lucy Kowis Ashton Kozeal Joseph Kozeal Michael Kozowyk Karey Kramer Pratt Kramer Joshua Kravitz Casey Krebsbach Madison Krejci James Kress Miles Krieger Vinisha Krishna Tyler Krug Leighanna Kruger Kevin Kuitu Tan Kulachanpises Abhinav Kumar Sapna Kumar Eric Kuntschik Sarah Kuo Jim Kurowski Zane Kurtz Jim Kuster Kenny Kuykendall Liz Labarre Amanda Labrie Phil Lacasse Kevin Lacey Shane Ladewig Craig Lahodny Agnes Lai Chaz Laijas Sara Lamar Philip Lamsens Jeff Landrum Randy Landrum Thomas Landrum Joe Landry Clinton Lane Jared Lane Jason Lang Brooke Langford Sean Langhout Bryan Lanier Annika Lanning Chris Lanning Stephanie Lannon Dean Lantrip Ny Lantrip Reese Lantrip Mickenzie Larsen Mark Larson Roy Larson Brock Laskowski Akeela Lassalle Gina Lauve Peggy Lavine Daniel Lawrence Taylor Lawrence Cynthia Lawson Donnie Lawson Dusty Lawson Herman Lawson Jaime Leal Madison Leaverton Brandy Ledbetter Kyle Ledford Gina Lee Kevin Lee Michelle Lee Dwayne Leera Philip Leimer Chance Leininger Jeffrey Leitzell

Jason Lemar Kristy Lemish Heath Lemon Benny Leonard Jacquelyn Leonard Dan Letch Brice Letcher Dillon Letherman Herman Leung Roberta Levick Randy Lewellen Angie Lewis Dan Lewis
Kande Lewis Katie Lewis Neil Lewis Adam Ley Chris Leyendecker Adrienne Leyva Helen Li Robert Li Mike Liang Anthony Licona Allen Light Gloria Light Jackie Lightner Morgan Likens
Shannon Lillie Kristen Limongelli Jie Lin Bradley Lindsey Michael Lindsley Gordon Linneman Eric Lippincott Scott Listiak Shane Litten David Little Henry Liu Newton Liu Martin Livingston
Matt Lizotte Sammy Lloyd John Lock Brian Locke Lee Lohoefer II Amber Long Dave Long Jennifer Long Chris Longoria Rey Longoria Brandyn Lonning Brian Lopez David Lopez Donna Lopez
Jerome Lopez Juan Lopez Mateo Lopez Michelle Lopez Robin Lopez Jeffrey Lorson Dustin Lott Cary Loughman Brent Louser John Love Robert Love Shaun Love Joey Lovell Doug Lowrie
Javier Lozano Jeremy Lozolla Andrew Lu Andres Lucas Josh Lucas Eric Luckey Steven Lukas Anibal Luna Davis Lunsford Paul Lunsford Al Lutes David Ly Eric Lyche Jocelyn Lyrock Nick Lyssy
Alex Mabrey Arthur Mackey Paula Mackey Rachel MacWithey Kyler Macy Stuti Madaan Kay Maddox Zach Madrazo Brandon Madrid Yolanda Maese Malissa Magee Devanand Maharaj Sarah Majors
Geri Malcolm Christina Maldonado Nick Malinaric Arvind Mallya Shawn Malsam Neil Malson Grace Mamaradlo Don Manton Fonda Manwell Wesley Maples Ken Marbach Anita Marin Pablo Marin
Anthony Marino Victoria Mariscal Walter Marler Colleen Marples Alex Marquez Michael Marquez Patrick Marsh Michelle Marshall Jessica Marten Hallie Martin Keith Martin Reese Martin
Rodney Martin Susan Martin Claudia Martinez Corrina Martinez Daniel Martinez Fernando Martinez Jimmy Martinez Paul Martinez Roland Martinez Sam Martinez Santiago Martinez Adriana Martinez-Holtz Margaret Martinez-Soza John Marx Leonardo Maschio Bob Masitti Aaron Mason Ashley Mason Matt Mason Rachel Matas Chris Mathews Beverly Matthews Mac Matthews Traci Matthews
Dennis Maupin Alec Mauritsen Mark Mauritsen Jeanna Maxwell Justin Maxwell Colter May Valerie May Anthony Mayes Ashley Mayfield Heather Mayfield Donnie Mayo Gene Maze Marc Mc Comie
Ron McBee Charles McCann David McCann Melissa McCarty Rick McCaslin Sophia McCatharn Audrey McCauley Kacey McCauley Amy McCauslin Colby McCay Tabitha McChesney Vanesa McClain
Nick McClelland Colleen McCorkell Stan McCracken Johnny McCray Jason Mcculloch Robert Mcculloch Tyler McCulloch Drew McDiarmid Shay McDonald David McDougall Misty McDowell
David McEachern Andrea McGarrah Bonnie McGehee Vickie Mcginnity Kimery McKaskle Michael McKenzie Mark Mckinney Jason McLaren Ross McLaughlin Raina McMillon Courtney McNeese
Curtis McTeigue Rick Mead Oscar Medellin Anacani Medina Owen Meinke Greg Meisner Carlos Melick Stephen Melnyk Brad Melton David Men Ethan Mendel Jackie Mendoza Patrick Mendoza
Iranell Menefee Marielle Mercurio London Mery Mark Metzger Gail Meyer Jeff Meyer Rob Meyer Eloise Meza Jane Mi Bryan Michalak Ronnie Michel Ryan Michel John Micheletto Travis Mihecoby
Traci Mikes Matt Miles Scott Miles Shante Miles Joe Milke Alex Miller Charles Miller Christopher Miller Edward Miller Greg Miller Sara Miller Tigar Miller Jinay Mills Leroy Mills Billy Milner
Andrew Mioduchowski Arnaldo Miranda Daisy Miranda Javier Miranda Amy Mitchell Justin Mocko Dana Moczygemba Chance Mogg Saaliha Mohammed Shazam Mohammed Ganesh Mohanrao
Frankie Molina Chelsea Monahan Tony Monariti Christopher Monger Jordan Monger Byron Monk George Monk Joel Monroe Rachael Monroe Jeremy Montanez Trini Montes Michael Montgomery
Gerardo Montoya Max Monty Ryan Moody Laura Moon Dave Moore Kutter Moore Leni Moore Yvette Moore Andrea Morales Miriam Morales Eunice Morales Montelongo Charles Moran Frank Moreno
Anna Morgan Lisa Morgan Michael Morgan Nancy Morgan Ted Morgan Doug Morgareidge Andre Morris Jared Morris Ashley Morrison Heath Morrison Jake Morrison Wes Morrison Anne Moses
Nephi Mourik Clayton Moy Pat Moya T.J. Moye Greg Mudgett Sonal Mujmer Chantel Mullen Jeremiah Mullen Jim Mullen Karen Mullins Norma Muncy Steve Munsell Madhavi Muralidhar
Daniel Muren Duberney Murillo Bill Murphy Courtney Murphy Emily Murphy Grady Murphy Katie Murphy Sam Murphy Ramey Musgrave Kendra Myer LB Myers Erin Nagle Lucia Nail Harry Nanan
Melissa Nance James Nanney Laura Napier Camille Nath Rachel Natividad Sylvia Navarrette Debra Navratil Lev Nayvelt Brian Neemar Raymond Neether Amanda Nelson Emily Nelson Gary Nelson
Clint Neshem Doug Ness Jacob Ness Jason Neugebauer Terry Newland William Newland Vern Newlin Dean Newman Lester Newsome Antoine Nguyen Bonny Nguyen Hanh Nguyen Hung Nguyen
Quynh Nguyen Tu Nguyen Tuyen Nguyen Yen Nguyen Sarah Nichols Kory Nickell Cory Nielsen Mary Nienkamp Jim Nies Richard Nies Jason Nikodym Orrison Niles Sherly Nissing Scott Nordstrom
Joel Noronha Tracey Norris Deborah Null Pancho Nye Jemine Oakes Travis Oatman Perry Obert Ryan O'Connell Ron Oden Laura Odom Lori Odom John O'Donnell Amos Oelking III Chieke Offurum
Geoffrey Ogden Rachael Ogilvie Julie Ogren Danny Olds James Olds Shawn Oleson Linda Olinick Victoria Olivas Raul Oliveira Dillon Oliver Jay Oliver Mathew Oliver Shelley Oliver Becky Olney
Kevin Olsen Dan Olson Christine Omadath Carrissa O'Meara Cody O'Neal Denton O'Neal Ricky O'Neal Darla O'Neill Tracy Opp Bill Orchard Kaitlin Oress Jeremy Ormsby Guillermo Orquiz Jay Orr
Rosa Ortega Juan Ortegon Diane Ortiz Peter Ortiz Cary Osiek Ann Osoba Kelly Ostdahl PJ Ostlund Craig Ostriyznick Richard Ott Jennifer Otterson Todd Overson Jessica Owens Denziel Owusu
Jerome Packineau Nathaniel Packineau Chad Paden Jessica Padilla-Cedillo Richard Pagel Wesley Paine Daniel Palacios Jennifer Palma Joe Palma Paul Palma Debra Palmer Amy Palmieri
Dom Palmieri Penny Pan Liz Panfely Troy Pank Allison Parizek John Park Cullen Parker Hillary Parker Katie Parker Kevin Parker Ancil Parks Ashley Parr Greg Parr Shane Pate Rati Patel
Tara Patten Brent Patterson Rob Patterson Brenna Patton Dallas Patton Doug Patton Anton Paul Jesse Pauls Bill Pauly Jason Pawelek Preston Pawelek Landon Pawlik Justin Payne Oscar Payne
Rafael Paz Annette Pearsall Arthur Pearson Philip Pearson Ty Pearson Sarah Peasley David Pederson Bret Pehacek Ignacio Pelayo Jody Pelzel Johnny Pena Gary Peng Ginny Penzell Sterling Pereira
Erick Perez Martha Perez Ruben Perez Tori Perez Victor Perez Sandy Perko Christian Perner Narine Persad Neil Persad Roy Persohn David Peterson Kyle Peterson Frank Petrutsas Angela Pettus
Anh Pham Phuong Pham Rita Pham Tai Pham Tony Pham Curtis Philip Gary Phillips Nestor Phillips Saunda Phillips Laura Piasecki Michael Pickell Sammy Pickering Elisabeth Pieper Dave Pieprzica
Sonja Pigeon Clint Pigg Scott Pilling Silvestre Pineda Catalin Pintea Eric Pitcher Rick Plaeger Catherine Plasencia Daniel Poche Brittany Poe Stephanie Poe Jami Pohl Justin Polasek Brian Policky
DeAnn Pollok Brian Pond Batina Poorbaugh Preston Pope David Popham Brianna Popowicz Lily Portales Brian Porter Chris Porter Jeremy Porter Jeff Porzondek Diane Posey Matthew Posey
Craig Poskus Phani Potturu Michael Pouba Allun Powell Ginny Powers Navan Powers Brian Prasek Jon Pratt Judy Prentice Christy Prescott Eli Presson Jon Prestwood Amy Price Debbie Price
Eric Price Juan Prieto Christina Prigmore Troy Pritchard Brittany Pritchett Stephen Proksell Steven Puente Dusty Pullin Conrad Puls Susana Purin Lance Pusley Jennifer Puzon Clint Pyeatt
Jeremy Pyle David Pyles Benny Quezada Shawn Quimby Judy Quintana Oelke Rick Quintela Shelley Quiring Michael Raab Shawn Racca Erick Rada Holly Radcliffe Reese Rademacher Blake Ragland
Casey Ragsdale Taryn Ragsdale Shashank Raizada Kishan Ramdeo Rennie Ramdeo Jay Ramineni Andrew Ramirez Diana Ramirez Eric Ramirez Luz Ramirez Priscella Ramirez Rudy Ramirez
Nigel Ramkhelawan Ann Ramlochan Anuradha Ramprakash Damian Ramsey Navindra Ramsingh Vishal Ramsook Hector Rangel Gary Ranger Tammy Rankin Jamie Raphael Dustin Rasmussen
Julie Rasmussen Rance Rasmussen Justin Rasmusson Surath Rath Cass Rathmann Jason Rauen Stuart Ray Michael Read Lauren Redmond Sean Redmond Bo Reed Bradley Reed Cody Reeh
Trent Reese Becky Reeves Garrett Reeves Derek Reiber Tracy Reid Courtney Reis Matt Reis Rick Reisenauer Michael Reiter Susan Reiter Christopher Rendall Wade Renken Renee Retana
Travis Rettig Lee Reuter Julie Rey Gabriel Reyes Patty Reyes Roland Reyes Ruth Reyes Ricardo Reyna Kit Reynolds Jeff Rezac Cristin Rhinehart Aaron Rhoades Chad Rice Darrell Rice
Michael Rice William Rice Cory Richard John RiChard LeeRoy Richards Janet Richardson Robert Richardson Mark Richeson Alex Richter Lynn Richter Lisa Rickard Shane Rickerson Grayson Ridgway
Janice Riedel Kendra Riggs Lee Ring Robert Rios Kim Risner Shane Rithmiller Kimberli Rivas Roy Roach John Robalin Glen Robbins Johnnie Roberts Bill Robertson Rachel Robertson Lisa Robichaux-Jones Jordan Robinson Kyle Robinson Rob Robinson Sam Robinson Elitha Rocke-Maharaj Colter Rodgers Alex Rodriguez Casey Rodriguez Daniel Rodriguez David Rodriguez Denzeal Rodriguez
Esther Rodriguez Jason Rodriguez Jason Rodriguez Jerry Rodriguez Justin Rodriguez Maryann Rodriguez Mayra Rodriguez Michelle Rodriguez Natalie Rodriguez Nate Rodriguez Victor Rodriguez
Dana Roesler Brandon Rogers Sheila Rogers Larry Romero Ramon Romero Alex Romo Carlos Romo Miguel Romo Robin Rood Seth Rorem Jessica Rosasco Jeff Rosato Greg Rose Randy Rose
Dick Rosencrans Ellen Rosencrans Pamela Roth Dallas Roundy Joseph Rouse Reed Roush Kyle Royal Dan Rozman Steve Ruiz Fabiola Ruiz Pelayo Doug Runkel Kyle Ruppe Michelle Russell
Will Russell Trint Rust Bradley Ruth Amy Rutledge Travis Rutledge Mel Ryan Richard Ryan Rick Rysavy Matthew Sabolchick Teresa Sadlowski Ashley Saelens Jayme Saenz-Anderson Sandy Salazar
Eduardo Saldana David Saldarriaga David Saldivar Suzanne Saldivar Gloria Salinas Gilbert Sambrano Mickey Sammy Natalie Samson Fabian Sanchez Bert Sanders Bobby Sanders John Sanders
Kathy Sandoval Ancil Sandy Jonathon Santone Juan Sarabia Daniel Sargent Raul Sarmiento Annette Saubon Nick Sauby Rodney Saucedo Rolando Saucedo Nathaniel Saumell Chris Saunders
Chloe Sawtelle Katy Scates Mark Scates Jeremy Schaffer Amber Schaller Garrett Schank Kelly Scharkopf Rick Schatz Jacob Scheel Brett Scheeler Wendi Scheier Stephen Schelling Gary Schill
Billy Schindler Colby Schindler Steve Schindler Brooke Schlemeyer Frank Schmidt Jon Schmidt Nathan Schneider Jr Schock Ty Schoon Carol Schornack Jarrett Schrade Mark Schram Jan Schroller
Eric Schulz Steven Schulz Aly Schuster Mike Schween Andy Scott Erik Scott Pat Scott Dave Scourfield Phillip Scruggs John Scull Sarah Searle Urban Seay Tom Sebastian Derek Secrest
Stuart Seger Baljit Sehbi Brandon Seidel Pat Seiser Brad Sekula Michelle Selensky Stephen Self Sarah Semer Meghan Sennett Christine Senter Andy Sepulveda Peter Sepulveda Hector Serna
Joe Serrano Jr. Bodee Sessions Mariani Setiawaty Chase Settle Chris Settle Diana Sewdass-Dabiedeen Greg Shaffer Austin Sharp Warren Sharp Dustin Sharpe Blake Shaw Gary Shaw Dan Shea
David Shedlowski Jen Sheehan Don Shelden Chuck Shelton Delmer Shelton Jeremy Shelton Joel Shelton Charlie Sheppard Wei Shi Ying Shi Lee Shipman Matthew Shoemaker Kevin Shomette
Andrew Shorrosh Keith Shuffler Michael Shultz Peter Si Jon Sicola Usman Siddiqui JD Siddoway Jay Siebens Antonio Sierra Chris Sikora Ed Sikora Chad Silverman Akash Simlote Steven Simmons
John Simon Chuck Simons Justin Simpson Matthew Simpson Palmer Simpson Sheela Singh Shivanand Singh Tim Singley Suvinay Sinha Jenna Sinopoli Mike Sipps Jason Sitchler Matthew Slocum
Brannon Slusher Summer Smart Jeff Smetanka Aubrey Smith Bobby Smith Brian Smith Caleb Smith Debbie Smith Drew Smith Jamie Smith Larry Smith Loren Smith Lori Smith Mark Smith
Matt Smith Michael Smith Richard Smith Shawn Smith Teresa Smith Todd Smith Wyatt Smitherman Gerek Smuin Kyle Smuin Sheree Smyzenski Bobby Snow Tyrel Snow Michael Sohmer
Olivia Soliman Eddie Solis Annie Soliz Martha Solomon Noah Son Carlos Sonka Higinio Sonora Nandini Sooklal-Balgobin Joel Sooter Clay Sorrells Michael Sosnowski Drew Soto Reid South
Wayne South Alan Spears Anslem Spears Debbie Spears Kelly Spears Woody Speer Christine Spencer Jeff Spencer Lindsay Spooner Ashley Springer Shawn Springfield Laura Sproles
Justin St. Julian Kristina St. Romain Adam Stafford Kristy Stahl Tammy Stambolis Korey Stammen Scott Stammen Delby Stanger Kathy Stanley Patricia Stanley Anthony Stanton Bridgett Staples
Kiera Staples Cindy Stapleton Mike Stapleton Rob Stark Hadden Starnes Charlie Steel Chad Steele Morgan Steele Lisa Steele-Pujadas Patti Steely Shari Stefinsky Jake Stephens Sheri Stephens
Cliff Stephenson Nathan Stephenson Bob Stepp Kim Stetler Colleen Stevens Jodi Stevens Michael Stevens Shanon Stevenson Brady Stewart Eric Stewart George Stewart Michele Stewart Richard
Stewart Zoltan Stiffel Cory Stinnett Jerry Stinson Jeff Stofa Austin Stoller Ted Stoltenberg Leslie Stone Natalie Stone Ryan Storro Rex Stout Parker Stovall Cindy Stowell Jeff Strahan Josh Stralow
Dan Strawn David Streit Brandon Stricker Bill Strickland Cody Strickland Vicky Strom Rusty Stroschein Dmytro Stryzhyboroda Alex Stuart Melissa Sturm Jorge Suarez Pete Subia Colin Sue
Jason Sugg Barry Sukal Sue Sule Bobby Sullivan Taylor Sullivan Stacy Suphal Brandon Swain Ryan Swallow Brian Swanson Gary Swedlund Sarah Swimm Sundai Swinney Sharon Sword
Grant Sykes Valarie Taber Jeb Tachick Curtis Tagliabue Ross Talboom Chris Talley Cristina Tamayo Scarlett Tang Brian Tapp Daniel Tate David Tate Radhika Tati Clint Taylor Daphne Taylor
David Taylor Dax Taylor Jackson Taylor John Taylor Lauren Taylor Trey Taylor David Tegtmeier Tyson Teichert Ralph Telford Jason Temple Corey Terrance Josh Terrell Cameron Terveen Lance Terveen
Tyson Thacker Liz Thai Matt Tharp Kyle Thebeau Cody Thiel Joshua Thoma Alex Thomas Angela Thomas Bill Thomas Chase Thomas Gary Thomas Jeremy Thomas Joe Thomas Martin Thomas
Melva Thomas Nelson Thomas Quincy Thomas Stephen Thomas Tyler Thomason Amanda Thompson Brian Thompson Chrissy Thompson Donna Thompson Drew Thompson Jerry Thompson
Kelcey Thompson Steve Thompson Greg Thornton Thomas Thornton Gary Thrasher Madhukar Thumma Dewayne Tidwell Dinah Tiff Jimmy Timbre Patrick Timlick Kevin Timm Beau Tinnin
Cameron Tisdale Andrell Titte Chistopher Titzman Scotty Tjepkes Nathan Tomerlin Christel Tomwing Mehmet Torcuk Stephanie Torres Clarence Trader Ryan Trader Dalton Tramell Ryan Tran Tan Tran
Tien Tran Keith Trasko Gary Travis Steven Travis Tyler Treece Nik Treffert Justin Trestrial Jennifer Trevino Roland Trevino Vale Trevino David Trice Ike Tripp Jonell Trodlier Joseph Troupe
Michael Trout Jennifer Trueblood Bobby Trujillo Shane Trulson Ravali Tummala JD Turbiville Larry Turbiville Derrick Turner Linda Turner Nicole Turner Jose Turrubiates Husein Tyebkhan Ben Tyler
Casey Tywater George Ulmo Joe Umphres Tull Umphres Joe Underbrink Amanda Underwood Raghu Upadhyay Dustin Upton Bradley Uran Joe Urbis Tammy Vader James Vaiana Andrew Valdez
Eddie Valek Keith Valentine Kelly Valerio Steve Valero Jaime Valles Chris Valvaneda Cary Van Degna Chris Van Degna VK Van Kirk Chase Van Valkingburg Brenda Vaness Rocio Vargas
Mike Vargo Martha Varice Kyle Varisco Bridger Vaselin Angela Vasquez Cissy Vasquez Erma Vazquez Tony Vazquez Tabitha Vedsted Jennifer Vega Emi Vela Cesar Velazquez Dave Vennes Russell
Vera Anjali Verma Matt Vickery George Vieira David Vigil Elling Vikesland Tara Viktorin Eric Villarreal Guillermo Villarreal David Villegas Issac Villegas Mariah Villegas Casey Vincik Michael Vito
Travis Voelkner Tim Vogler Dwayne Voigt Maria Volodina Prody Vong Jordan Vonroeder Diana Voss Bob Vote Sandy Vu Darren Wacha Sandeep Wagle Jessica Wagner John Wagner Stan Wagner
Dennis Wagstaff Tony Wahus Logan Waldrip Casey Walk Gary Walker John Walker Kristi Walker Kyle Walker Tracy Walker Justin Wallace Josh Wallis Michele Walls Wanda Walls Dylan Walrond
Joseph Walthall Chuck Walton Kip Walton Cindy Wang Xinchuan Wang Ralph Warby Justin Ward Lance Ward Melissa Ward Travis Wardlaw Zachary Wardlaw Scott Ware Jackie Warner Ben Warren
Tamara Warton Andrew Washburn Danielle Watson Laura Watts Chinmay Watve Kristyn Weaver Mike Weaver Chris Webb Heidi Webb Bradley Webber Cody Weddle Derek Weicht
KC Weiland Brandt Weimar Chad Weisenburger Creighton Welch Dustin Welch Geoff Welch Janet Welch Michael Welch Kelly Welk Ethan Wellman Amanda Wells Nathan Wells Tonya Wemm
Amy Wen Steve Wentworth Cally Wescoat Brian West Jeremy West Robert West Ryan West Brandon Westerholm Erica Westphalen Ty Westphalen Niles Wethington Julie Whalen Mary Ann Whetzal
Luke Whidden Michelle Whidden Justin Whipple Roland Whitaker Keri White Lonnie White Matthew White Mike White Taylor Whitecotton Cody Whitehead Jerrold Whitehead
Josh Whitener Kevin Whitley Jonathan Wiatrek Troy Wiatrek Eli Wiechmann Shane Wiest Mark Wiley Trace Wilhoit Blake Wilkins Dustin Wilkins Robert Wilkins Sharon Wilkinson
Dan Wilkirson Dale Willenbring Andrew Willett Ron Willett April Willette Aaron Williams AJ Williams Anthony Williams Cody Williams Janet Williams Jeanette Williams Joey Williams
Rick Williams Robert Williams Sheri Williams Greg Williamson Matthew Williamson Carl Willms Casey Wills Brandon Wilson Donnie Wilson James Wilson Kathie Wilson Roger Wilson
Jeff Wilt Nina Wiltz Corey Windham Wink Winkelman Brian Winkleman Dustin Winkler Kris Winland Scotty Winter David Winters George Witman Jared Wolf Shelia Wolfe Hatch Womack Mary Womack
Jefferson Wood Lanny Wood Seth Woodard Pat Woods Amy Woodward Justin Woodward Heath Work Kacy Work Seth Workman Robert Worley Lloyd Woychuk Cameron Wright
Dan Wright Junjie Wu Oscar Wu Justin Wyatt Hong Xiao Ezra Yacob John Yang Nikki Yang Raymond Yang Malcolm Yates Otis Yates Randy Ybarra Vijay Yelaka Michael Yemm Barbara Yin Lau Yip
Joe Yohe Maggie Yokley Chelsey Young Russ Young Sherman Young Jarrod Youngblood Dianne Younger Cissy Yu Eric Yu Jennifer Yu Josh Zahn Omar Zakaria Zack Zakaria Zeinab Zamani
Sarah Zankey Saeed Zargari Miguel Zavala Dean Zebak Tommy Zhang Tracy Zhang Andy Zheng Tracy Zhou Zach Zigmond Hannah Zinser Jaymie Zombotti Maison Zuber Amber Zuchara

EOG OPERATIONS

WORLDWIDE	
2017 Production	222 MMBoe
2017 Year-End Proved Reserves	2,527 MMBoe
UNITED STATES	
2017 Production	201 MMBoe
2017 Year-End Proved Reserves	2,457 MMBoe
TRINIDAD AND TOBAGO	
2017 Production	19 MMBoe
2017 Year-End Proved Reserves	53 MMBoe
OTHER INTERNATIONAL	
2017 Production	2 MMBoe
2017 Year-End Proved Reserves	17 MMBoe



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