

MARATHON OIL CORP  
Form 10-K  
February 21, 2019

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UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549  
FORM 10-K  
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)  
OF THE SECURITIES EXCHANGE ACT OF 1934  
For the Fiscal Year Ended December 31, 2018  
Commission file number 1-5153  
Marathon Oil Corporation  
(Exact name of registrant as specified in its charter)  
Delaware 25-0996816  
(State or other jurisdiction of incorporation or organization) (I.R.S. Employer Identification No.)  
5555 San Felipe Street, Houston, TX 77056-2723  
(Address of principal executive offices)  
(713) 629-6600  
(Registrant's telephone number, including area code)  
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 \$1.00 New York Stock Exchange  
Securities registered pursuant to Section 12(g) of the Act: None

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Large accelerated filer  Accelerated filer  Non-accelerated filer   
Smaller reporting company  Emerging growth company

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes  No   
The aggregate market value of Common Stock held by non-affiliates as of June 30, 2018: \$17,781 million. This amount is based on the closing price of the registrant's Common Stock on the New York Stock Exchange on that date. Shares of Common Stock held by executive officers and directors of the registrant are not included in the computation. The registrant, solely for the purpose of this required presentation, has deemed its directors and executive officers to be affiliates.

There were 818,504,459 shares of Marathon Oil Corporation Common Stock outstanding as of February 14, 2019.

**Documents Incorporated By Reference:**

Portions of the registrant's proxy statement relating to its 2019 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this report.

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## MARATHON OIL CORPORATION

Unless the context otherwise indicates, references to "Marathon Oil," "we," "our" or "us" in this Annual Report on Form 10-K are references to Marathon Oil Corporation, including its wholly owned and majority-owned subsidiaries, and its ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon Oil exerts significant influence by virtue of its ownership interest).

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## Definitions

Throughout this report, the following company or industry specific terms and abbreviations are used.

AMPCO – Atlantic Methanol Production Company LLC, a company located in Equatorial Guinea in which we own a 45% equity interest.

AOSP – Athabasca Oil Sands Project, an oil sands mining, transportation and upgrading joint venture located in Alberta, Canada, in which we held a 20% non-operated working interest.

bbl – One stock tank barrel, which is 42 United States gallons liquid volume.

bcf – Billion cubic feet.

boe – Barrels of oil equivalent.

btu – British thermal unit, an energy equivalence measure.

Capital Budget – Includes capital expenditures, cash investments in equity method investees and other investments, exploration costs that are expensed as incurred rather than capitalized, such as geological and geophysical costs and certain staff costs, and other miscellaneous investment expenditures.

Development Capital Budget – Includes expenditures, investments and costs associated with the Capital Budget excluding resource play leasing and exploration ("REx").

DD&A – Depreciation, depletion and amortization.

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

Dry well – A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

E.G. – Equatorial Guinea.

EGHoldings – Equatorial Guinea LNG Holdings Limited, a liquefied natural gas production company located in E.G. in which we own a 60% equity interest.

EPA – United States Environmental Protection Agency.

E&P – Exploration and production.

Exploratory well – A well drilled to find oil or natural gas in an unproved area or find a new reservoir in a field previously found to be productive in another reservoir.

FASB – Financial Accounting Standards Board.

Henry Hub price – a natural gas benchmark price quoted at settlement date average.

IRS – United States Internal Revenue Service.

Kurdistan – Kurdistan Region of Iraq

LNG – Liquefied natural gas.

LPG – Liquefied petroleum gas.

Liquid hydrocarbons or liquids – Collectively, crude oil, condensate and natural gas liquids.

LLS – Louisiana Light Sweet crude oil, an oil index benchmark price as per Bloomberg Finance LLP: LLS St. James.

Marathon Oil – Marathon Oil Corporation, including wholly owned and majority-owned subsidiaries, and ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon Oil exerts significant influence by virtue of its ownership interest). The company as it exists following the June 30, 2011 spin-off of the refining, marketing and transportation operations.

mbbl/d – Thousand barrels per day.

mboed – Thousand barrels of oil equivalent per day.

mcf – Thousand cubic feet.

mmbbl – Million barrels.

mmboe – Million barrels of oil equivalent. Natural gas is converted on the basis of six mcf of gas per one barrel of crude oil equivalent.

mmbtu – Million British thermal units.

mmcf/d – Million stabilized cubic feet per day.

mmta – Million metric tonnes per annum.

MPC – Marathon Petroleum Corporation – the separate independent company, which owns and operates the refining, marketing and transportation operations.

mt – metric tonnes

mtd – metric tonnes per day.

Net acres or Net wells – The sum of the fractional working interests owned by us in gross acres or gross wells.

NGL or NGLs – Natural gas liquid or natural gas liquids, which are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline, which can be collectively removed from produced natural gas, separated into these substances and sold.

NYMEX – New York Mercantile Exchange.

OECD – Organization for Economic Cooperation and Development.

OPEC – Organization of Petroleum Exporting Countries.

Operational availability – A term used to measure the ability of an asset to produce to its maximum capacity over a specified period of time, after consideration of internal losses.

Productive well – A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

Proved developed reserves – Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of the required equipment is relatively minor compared to the cost of a new well.

Proved reserves – Proved crude oil and condensate, NGLs, natural gas and our historical synthetic crude oil reserves are those quantities of crude oil and condensate, NGLs, natural gas and synthetic crude oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved undeveloped reserves – Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having proved undeveloped reserves if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Reserves on undrilled acreage shall be 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 viability at greater distances.

Reserve replacement ratio – A ratio which measures the amount of proved reserves added to our reserve base during the year relative to the amount of liquid hydrocarbons and natural gas produced.

Royalty interest – An interest in an oil or natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

SAR or SARs – Stock appreciation right or stock appreciation rights.

SCOOP – South Central Oklahoma Oil Province.

SEC – United States Securities and Exchange Commission.

Seismic – An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures and 4-D factors in changes that occurred over time).

STACK – Sooner Trend, Anadarko (basin), Canadian (and) Kingfisher (counties).



TD – Total depth or the bottom of a drilled hole.

Total proved reserves – The summation of proved developed reserves and proved undeveloped reserves.

U.K. – United Kingdom.

U.S. – United States of America.

U.S. resource plays – Consists of our unconventional properties in the Oklahoma, Eagle Ford, Bakken and Northern Delaware.

U.S. GAAP – U.S. Generally Accepted Accounting Principles.

Working interest – The interest in a mineral property, which gives the owner that share of production from the property.

A working interest owner bears that share of the costs of exploration, development and production in return for a share of production. Working interests are sometimes burdened by overriding royalty interests or other interests.

WTI – West Texas Intermediate crude oil, an oil index benchmark price as quoted by NYMEX.



### Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including without limitation: our operational, financial and growth strategies, including drilling plans and projects, planned wells, rig count, inventory, seismic, exploration plans, maintenance activities, drilling and completion improvements, cost reductions, non-core asset sales, and financial flexibility; our ability to successfully effect those strategies and the expected timing and results thereof; our 2019 Capital Budget and the planned allocation thereof; planned capital expenditures and the impact thereof; expectations regarding future economic and market conditions and their effects on us; our financial and operational outlook, and ability to fulfill that outlook; our financial position, balance sheet, liquidity and capital resources, and the benefits thereof; resource and asset potential; reserve estimates; growth expectations; and future production and sales expectations, and the drivers thereof. In addition, many forward-looking statements may be identified by the use of forward-looking terminology such as “anticipates,” “believes,” “estimates,” “expects,” “targets,” “plans,” “projects,” “could,” “may,” “should,” “would” or similar words indicating that future outcomes are uncertain. While we believe that our assumptions concerning future events are reasonable, these expectations may not prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to:

- conditions in the oil and gas industry, including supply and demand levels for crude oil and condensate, NGLs and natural gas and the resulting impact on price;
- changes in expected reserve or production levels;
- changes in political or economic conditions in the jurisdictions in which we operate, including changes in foreign currency exchange rates, interest rates, inflation rates, and global and domestic market conditions;
- risks related to our hedging activities;
- liability resulting from litigation;
- capital available for exploration and development;
- the inability of any party to satisfy closing conditions or delays in execution with respect to our asset acquisitions and dispositions;
- drilling and operating risks;
- lack of, or disruption in, access to pipelines or other transportation methods;
- well production timing;
- availability of drilling rigs, materials and labor, including the costs associated therewith;
- difficulty in obtaining necessary approvals and permits;
- non-performance by third parties of their contractual obligations;
- unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto;
- cyber-attacks;
- changes in safety, health, environmental, tax and other regulations;
- other geological, operating and economic considerations; and

other factors discussed in Item 1. Business, Item 1A. Risk Factors, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and elsewhere in this report.

All forward-looking statements included in this report are based on information available to us on the date of this report. Except as required by law, we undertake no obligation to revise or update any forward-looking statements as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.



## PART I

### Item 1. Business

#### General

Marathon Oil Corporation (NYSE: MRO) is an independent exploration and production company based in Houston, Texas, focused on U.S. resource plays with operations in the United States, Europe and Africa. Our corporate headquarters is located at 5555 San Felipe Street, Houston, Texas 77056-2723 and our telephone number is (713) 629-6600. Each of our two reportable operating segments are organized by geographic location and managed according to the nature of the products and services offered. The two segments are:

• United States – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States;

• International – explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of the United States and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G. We were incorporated in 2001. On July 1, 2011 we became an Independent E&P after we completed the spin-off of our refining, marketing and transportation business, creating two independent energy companies: Marathon Oil and MPC.

Our strategy is to deliver competitive and improving corporate level returns by focusing our capital investment in the lower cost, higher margin U.S. resource plays while maintaining a peer-leading balance sheet, prioritizing sustainable cash flow generation at conservative oil prices, and returning capital to shareholders. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, for a more detailed discussion of our operating results, cash flows and liquidity.

Our portfolio is concentrated in our core operations in the U.S. resource plays and E.G. The map below shows the locations of our core operations:

\* Our additional locations include the U.K, the Kurdistan Region of Iraq (executed a sales agreement in 2018) and other United States locations.

#### Segment Information

In the following discussion regarding our United States and International segments, references to net wells, acres, sales or investment indicate our ownership interest or share, as the context requires. During the year, we renamed our United States E&P and International E&P segments to the United States and International segments. The characteristics and composition of these segments remained unchanged and there was no effect on previously reported segment information. See Note 1 for further information.

## United States Segment

We are engaged in oil and gas exploration, development and production activities in the U.S. Our primary focus in the United States segment is concentrated within our four high quality resource plays. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for further detail on current year results.

### United States – U.S. Resource Plays

**Eagle Ford** – We have been operating in the South Texas Eagle Ford play since 2011, where roughly two thirds of our acreage is located in Karnes and Atascosa Counties. Our focus is capital efficient development with a goal of maximizing returns and cash flow generation while extending our core acreage. We operate 32 central gathering and treating facilities across the play that support more than 1,600 producing wells. We also own and operate the Sugarloaf gathering system, a 42-mile natural gas pipeline through the heart of our acreage in Karnes and Atascosa Counties.

**Bakken** – We have been operating in the Williston Basin since 2006. The majority of our core acreage is within McKenzie, Mountrail, and Dunn Counties in North Dakota targeting the Middle Bakken and Three Forks reservoirs. We continue focusing our investment in our high-return Myrmdon and Hector areas, while also delineating our position across the rest of our acreage.

**Oklahoma** – With a history in Oklahoma that dates back more than 100 years, our primary focus has recently been the transition to early infill development in the STACK Meramec and SCOOP Woodford, while progressing delineation of other plays across our footprint. We primarily hold net acreage with rights to the Woodford, Springer, Meramec, Osage and other prospect intervals, with a majority of this in the SCOOP and STACK.

**Northern Delaware** – We have been operating in the Northern Delaware basin, which is located within the greater Permian area, since we closed on two major acquisitions in 2017. These acquisitions gave us a strong foundational footprint in the region where we have the majority of our acreage in Eddy and Lea counties primarily in the Wolfcamp and Bone Spring New Mexico plays. Our focus since entering the play has been to strategically advance our position and prepare for future development by further coring up our footprint, progressing early delineation of our acreage, improving our cost structure and securing midstream solutions. See Item 8. Financial Statements and Supplementary Data – Note 4 to the consolidated financial statements for further detail.

### Other United States

Our remaining properties in the United States primarily consist of our newly acquired acreage in the emerging Louisiana Austin Chalk play and outside operated assets in the Gulf of Mexico, including our 3.5% overriding royalty interest in the Ursa fields. During 2018 we acquired approximately 260,000 net acres in the Louisiana Austin Chalk play at a cost of less than \$850 per acre. Additionally, in the fourth quarter 2018, we entered into an agreement to sell our working interest in the Droszky field, in the Gulf of Mexico, and as a result it is classified as held for sale in the consolidated balance sheet at December 31, 2018. This transaction closed in the first quarter of 2019.

During 2018 we closed on the sale of several non-core conventional properties, see Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements for further detail.

### International Segment

We are engaged in oil and gas development and production across our international locations primarily in E.G. and U.K. We include the results of our LPG processing plant, gas liquefaction operations and methanol production operations in E.G. in our International segment.

#### International

**Equatorial Guinea** – We own a 63% operated working interest under a production sharing contract in the Alba field and an 80% operated working interest in Block D, both of which are offshore E.G. Operational availability from our company-operated facilities averaged approximately 97% in 2018.

**Equatorial Guinea – Gas Processing** – We own a 52% interest in Alba Plant LLC, accounted for as an equity method investment, which operates an onshore LPG processing plant located on Bioko Island. Alba field natural gas, under a long-term contract at a fixed price per btu, is processed by the LPG plant. The LPG plant extracts secondary condensate and LPG from the natural gas stream and uses some of the remaining dry natural gas in its operations.

We also own 60% of EGHoldings and 45% of AMPCO, both accounted for as equity method investments.

EGHoldings operates a 3.7 mmta LNG production facility and AMPCO operates a methanol plant, both located on Bioko Island. These facilities allow us to further monetize natural gas production from the Alba field. The LNG

production facility sells LNG under a 3.4 mmta sales and purchase agreement. Under the agreement, which runs through 2023, the purchaser takes delivery of the LNG on Bioko Island, with pricing linked principally to the Henry Hub index. Gross sales of LNG from this production facility

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totaled approximately 3.5 mmta in 2018. AMPCO had gross sales totaling approximately 1,000 mt in 2018. Methanol production is sold to customers in Europe and the U.S.

United Kingdom – Our operated assets in the U.K. sector of the North Sea are the Brae area complex where we have a 42% working interest in the South, Central, North and West Brae fields, a 39% working interest in the East Brae field, and a 28% working interest in the nearby Braemar field. We own non-operated working interests in the Foinaven area complex, consisting of a 28% working interest in the main Foinaven field, a 47% working interest in East Foinaven and a 20% working interest in the T35 and T25 fields.

Libya – In the first quarter of 2018, we closed on the sale of our subsidiary, Marathon Oil Libya Limited, which held our 16.33% non-operated interest in the Waha concessions in Libya. See Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements for further detail.

#### Other International

Kurdistan Region of Iraq – We have a non-operated 15% working interest in the Atrush block located north-northwest of Erbil. During the fourth quarter of 2018, we entered into an agreement to sell our Kurdistan subsidiary, Marathon Oil KDV B.V., and as a result it is classified as held for sale in the consolidated balance sheet at December 31, 2018. We expect this transaction to close in the first half of 2019 which will complete our full country exit from Kurdistan. Additionally during 2018, we entered into separate agreements to sell certain non-core properties in our International segment. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions.

#### Reserves

Proved reserves are required to be disclosed by continent and by country if the proved reserves related to any geographic area, on an oil equivalent barrel basis, represent 15% or more of our total proved reserves. A geographic area can be an individual country, group of countries within a continent or a continent. Other International ("Other Int'l"), includes the U.K. and the Kurdistan Region of Iraq. Approximately 86% of our proved reserves are located in OECD countries, with 84% located within the U.S.

The following tables set forth estimated quantities of our total proved crude oil and condensate, NGLs and natural gas reserves based upon SEC pricing for period ended December 31, 2018.

December 31, 2018	U.S.	E.G.	Other Int'l	Total
Proved Developed Reserves				
Crude oil and condensate (mmbbl)	287	36	22	345
Natural gas liquids (mmbbl)	119	22	—	141
Natural gas (bcf)	869	715	7	1,591
Total proved developed reserves (mmboe)	552	176	24	752
Proved Undeveloped Reserves				
Crude oil and condensate (mmbbl)	308	—	3	311
Natural gas liquids (mmbbl)	105	—	—	105
Natural gas (bcf)	684	—	—	684
Total proved undeveloped reserves (mmboe)	526	—	3	529
Total Proved Reserves				
Crude oil and condensate (mmbbl)	595	36	25	656
Natural gas liquids (mmbbl)	224	22	—	246
Natural gas (bcf)	1,553	715	7	2,275
Total proved reserves (mmboe)	1,078	176	27	1,281

Of the total estimated proved reserves, approximately 51% was crude oil and condensate. As of December 31, 2018, our estimated proved developed reserves totaled 752 mmboe or 59% and estimated proved undeveloped reserves totaling 529 mmboe or 41% of our total proved reserves. For additional detail on reserves, see Item 8. Financial Statements and Supplementary Data - Supplementary Information on Oil and Gas Producing Activities.



## Productive and Drilling Wells

For our United States and International segments, the following table sets forth gross and net productive wells, service wells and drilling wells as of December 31 for the years presented.

	Productive Wells								
	Oil		Natural Gas		Service Wells		Drilling Wells		
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	
2018									
U.S. (a)	4,630	2,056	1,703	655	209	21	43	18	
E.G.	—	—	19	12	—	—	—	—	
Other International	62	22	11	4	24	8	—	—	
Total	4,692	2,078	1,733	671	233	29	43	18	
2017									
U.S.	5,132	1,905	1,690	676	799	70			
E.G.	—	—	19	12	—	—			
Libya (b)	1,071	175	7	2	94	16			
Total Africa	1,071	175	26	14	94	16			
Other International	61	22	19	7	23	8			
Total	6,264	2,102	1,735	697	916	94			
2016									
U.S.	4,533	1,650	1,830	708	821	85			
E.G.	—	—	17	11	2	1			
Libya	1,071	175	7	1	94	16			
Total Africa	1,071	175	24	12	96	17			
Other International	62	23	35	14	23	8			
Total	5,666	1,848	1,889	734	940	110			

(a) The 2018 decrease in gross productive oil wells and gross service wells is a result of the sale of non-core, non-operated conventional properties in the United States segment during the third quarter of 2018. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions.

(b) Libya was removed from 2018 due to the sale of our subsidiary in Libya, see Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for further information.



## Drilling Activity

For our United States and International segments, the table below sets forth, by geographic area, the number of net productive and dry development and exploratory wells completed as of December 31 for the years represented.

	Development				Exploratory				Total
	Oil	Natural Gas	Dry	Total	Oil	Natural Gas	Dry	Total	
2018									
U.S.	171	25	—	196	66	36	2	104	300
E.G.	—	—	—	—	—	—	1	1	1
Other International	—	—	—	—	—	—	—	—	—
Total	171	25	—	196	66	36	3	105	301
2017									
U.S.	107	27	—	134	88	16	—	104	238
E.G.	—	—	—	—	—	—	—	—	—
Libya	—	—	—	—	—	—	—	—	—
Total Africa	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	2	2	2
Total	107	27	—	134	88	16	2	106	240
2016									
U.S.	64	12	—	76	70	27	3	100	176
E.G.	—	—	—	—	—	—	—	—	—
Libya	—	—	—	—	—	—	1	—	—
Total Africa	—	—	—	—	—	—	1	1	1
Other International	—	—	—	—	—	—	—	—	—
Total	64	12	—	76	70	27	4	101	177

## Acreage

We believe we have satisfactory title to our United States and International properties in accordance with standards generally accepted in the industry; nevertheless, we can be involved in title disputes from time to time which may result in litigation. In the case of undeveloped properties, an investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. Our title to properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the industry. In addition, our interests may be subject to obligations or duties under applicable laws or burdens such as net profits interests, liens related to operating agreements, development obligations or capital commitments under international production sharing contracts or exploration licenses.

The following table sets forth, by geographic area, the gross and net developed and undeveloped acreage held in our United States and International segments as of December 31, 2018.

(In thousands)	Developed		Undeveloped		Developed and Undeveloped	
	Gross	Net	Gross	Net	Gross	Net
	U.S.	1,352	1,004	484	356	1,836
E.G.	82	67	54	36	136	103
Other International	82	29	71	12	153	41
Total	1,516	1,100	609	404	2,125	1,504

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. If production is not established or we take no other action to extend the terms of the leases, licenses or concessions, undeveloped acreage listed in the table below will expire over the next three years. We plan to continue the terms of certain of these licenses and concession areas or retain leases through operational or administrative actions.

	Net Undeveloped Acres Expiring		
	Year Ended December 31,		
(In thousands)	2019	2020	2021
U.S.	31	64	134
E.G. <sup>(a)</sup>	36	—	—
Total	67	64	134

<sup>(a)</sup> This relates to the conclusion of our evaluation of drilling opportunities on the Rodo well in Alba Block Sub Area B, offshore E.G. and in 2018 determined that we would not pursue further activity.

Net Sales Volumes

	Africa				Other	Cont	Disc	
	U.S.	E.G.	Libya	Int'l	Int'l	Ops	Ops	Total
Year Ended December 31,								
2018								
Crude and condensate (mmbld) <sup>(a)</sup>	171	17	7	15	210	—	210	
Natural gas liquids (mmbld)	55	11	—	—	66	—	66	
Natural gas (mmcf) <sup>(b)</sup>	429	416	5	14	864	—	864	
Total sales volumes (mboed)	298	97	8	17	420	—	420	
2017								
Crude and condensate (mmbld) <sup>(a)</sup>	133	21	19	12	185	—	185	
Natural gas liquids (mmbld)	43	11	—	1	55	—	55	
Natural gas (mmcf) <sup>(b)</sup>	348	459	4	22	833	—	833	
Synthetic crude oil (mmbld) <sup>(c)</sup>	—	—	—	—	—	18	18	
Total sales volumes (mboed)	234	109	20	16	379	18	397	
2016								
Crude and condensate (mmbld) <sup>(a)</sup>	131	20	3	12	166	—	166	
Natural gas liquids (mmbld)	40	11	—	—	51	—	51	
Natural gas (mmcf) <sup>(b)</sup>	314	425	—	28	767	—	767	
Synthetic crude oil (mmbld) <sup>(c)</sup>	—	—	—	—	—	48	48	
Total sales volumes (mboed)	223	102	3	17	345	48	393	

<sup>(a)</sup> The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

<sup>(b)</sup> Includes natural gas acquired for injection and subsequent resale.

<sup>(c)</sup> Upgraded bitumen excluding blendstocks.

Average Production Cost per Unit<sup>(a)</sup>

	Africa				Other	Cont	Disc	
(Dollars per boe)	U.S.	E.G.	Libya	Int'l	Int'l	Ops	Ops	Total

2018	\$9.83	\$1.91	\$4.35	\$30.02	\$8.68	\$	—\$8.68
2017	9.49	2.12	6.08	26.61	7.90	29.72	9.23
2016	9.84	2.17	N.M.	23.13	8.41	29.36	11.02

(a) Production, severance and property taxes are excluded; however, shipping and handling as well as other operating expenses are included in the production costs used in this calculation. See Item 8. Financial Statements and Supplementary Data – Supplementary Information on Oil and Gas Producing Activities - Results of Operations for Oil and Gas Production Activities for more information regarding production costs.

N.M. Not meaningful information due to limited sales.

Average Sales Price per Unit<sup>(a)</sup>

(Dollars per unit)	Africa				Other Int'l	Disc Ops	Total
	U.S.	E.G.	Libya	Total			
2018							
Crude and condensate (bbl)	\$63.11	\$55.28	\$73.75	\$60.65	\$70.39	\$	-\$63.32
Natural gas liquids (bbl)	24.54	1.00	<sup>(b)</sup> —	1.00	41.66	—	20.85
Natural gas (mcf)	2.65	0.24	<sup>(b)</sup> 4.57	0.30	8.03	—	1.58
2017							
Crude and condensate (bbl)	\$49.35	\$46.02	\$60.72	\$53.11	\$52.66	\$	-\$50.38
Natural gas liquids (bbl)	20.55	1.00	<sup>(b)</sup> —	1.00	39.65	—	16.65
Natural gas (mcf)	2.84	0.24	<sup>(b)</sup> 5.03	0.28	6.28	—	1.51
Synthetic crude oil (bbl)	—	—	—	—	—	47.39	47.39
2016							
Crude and condensate (bbl)	\$38.57	\$38.85	\$57.69	\$40.95	\$43.21	\$	-\$39.23
Natural gas liquids (bbl)	13.15	1.00	<sup>(b)</sup> —	1.00	26.41	—	10.68
Natural gas (mcf)	2.38	0.24	<sup>(b)</sup> —	0.24	4.80	—	1.26
Synthetic crude oil (bbl)	—	—	—	—	—	37.57	37.57

<sup>(a)</sup> Excludes gains or losses on commodity derivative instruments.

Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and/or EGHoldings,

<sup>(b)</sup> which are equity method investees. We include our share of income from each of these equity method investees in our International Segment.

## Marketing

Our reportable operating segments include activities related to the marketing and transportation of substantially all of our crude oil and condensate, NGLs and natural gas. These activities include the transportation of production to market centers, the sale of commodities to third parties and the storage of production. We balance our various sales, storage and transportation positions in order to aggregate volumes to satisfy transportation commitments and to achieve flexibility within product types and delivery points. Such activities can include the purchase of commodities from third parties for resale.

## Gross Delivery Commitments

We have committed to deliver gross quantities of crude oil and condensate, NGLs and natural gas to customers under a variety of contracts. As of December 31, 2018, the contracts for fixed and determinable quantities were at variable, market-based pricing and related primarily to the following commitments:

	2019	2020	2021	Thereafter	Commitment Period Through
Eagle Ford					
Crude and condensate (mbbld)	65	51	—	—	2020
Natural gas liquids (mbbld)	1	—	—	—	2020
Natural gas (mmcf)	120	120	56	36	2022
Bakken					
Crude and condensate (mbbld)	10	10	10	5 - 10	2027
Natural gas (mmcf)	3	3	3	3 - 25	2028
Northern Delaware					
Crude and condensate (mbbld)	21	19	—	—	2020

All of these contracts provide the options of delivering third-party volumes or paying a monetary shortfall penalty if production is inadequate to satisfy our commitment. In addition to the contracts discussed above, we have entered into numerous agreements for transportation and processing of our equity production. Some of these contracts have volumetric requirements which could require monetary shortfall penalties if our production is inadequate to meet the terms.



## Competition

Competition exists in all sectors of the oil and gas industry and we compete with major integrated and independent oil and gas companies, as well as national oil companies. We compete, in particular, in the exploration for and development of new reserves, acquisition of oil and natural gas leases and other properties, the marketing and delivery of our production into worldwide commodity markets and for the labor and equipment required for exploration and development of those properties. Principal methods of competing include geological, geophysical, and engineering research and technology, experience and expertise, economic analysis in connection with portfolio management, and safely operating oil and gas producing properties. See Item 1A. Risk Factors for discussion of specific areas in which we compete and related risks.

## Environmental, Health and Safety Matters

The Health, Environmental, Safety and Corporate Responsibility Committee of our Board of Directors is responsible for overseeing our position on public issues, including environmental, health and safety matters. Our Corporate Health, Environment, Safety and Security organization has the responsibility to ensure that our operating organizations maintain environmental compliance systems that support and foster our compliance with applicable laws and regulations. Committees comprised of certain of our officers review our overall performance associated with various environmental compliance programs. We also have a Corporate Emergency Response Team which oversees our response to any major environmental or other emergency incident involving us or any of our properties.

Our businesses are subject to numerous laws and regulations relating to the protection of the environment, health and safety at the national, state and local levels. These laws and their implementing regulations and other similar state and local laws and rules can impose certain operational controls for minimization of pollution or recordkeeping, monitoring and reporting requirements or other operational or siting constraints on our business, result in costs to remediate releases of regulated substances, including crude oil, into the environment, or require costs to remediate sites to which we sent regulated substances for disposal. In some cases, these laws can impose strict liability for the entire cost of clean-up on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others (such as prior owners or operators of our assets) or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. We have incurred and will continue to incur capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. New laws have been enacted and regulations are being adopted by various regulatory agencies on a continuing basis and the costs of compliance with these new laws and regulations can only be broadly appraised until their implementation becomes more defined.

For a discussion of environmental capital expenditures and costs of compliance for air, water, solid waste and remediation, see Item 3. Legal Proceedings and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

## Air and Climate Change

Environmental advocacy groups and regulatory agencies in the United States and other countries have focused considerable attention on the emissions of carbon dioxide, methane and other greenhouse gases and their potential role in climate change. Developments in greenhouse gas initiatives may affect us and other similarly situated companies operating in the oil and gas industry. As part of our commitment to environmental stewardship, we estimate and publicly report greenhouse gas emissions from our operations. We are working to continuously improve the accuracy and completeness of these estimates. In addition, we continuously strive to improve operational and energy efficiencies through resource and energy conservation where practicable and cost effective.

Government entities and other groups have filed lawsuits in several states and other jurisdictions seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions attributable to those fuels. The lawsuits allege damages as a result of global warming and the plaintiffs are seeking unspecified damages and abatement under various tort theories. Marathon Oil has been named as a defendant in several of these lawsuits, along with numerous other companies. Similar lawsuits may be filed in other jurisdictions. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the claims made against us are without merit and will not have a material adverse effect on our consolidated financial position, results

of operations or cash flow.

The EPA finalized a more stringent National Ambient Air Quality Standard (“NAAQS”) for ozone in October 2015. States that contain any areas designated as non-attainment, and any tribes that choose to do so, will be required to complete development of implementation plans in the 2020-2021 time frame. The EPA may in the future designate additional areas as non-attainment, including areas in which we operate, which may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Although there may be

an adverse financial impact (including compliance costs, potential permitting delays and increased regulatory requirements) associated with this revised regulation, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the present uncertainty regarding any additional measures and how they will be implemented. The EPA's final rule has been judicially challenged by both industry and other interested parties, and the outcome of this litigation may also impact implementation and revisions to the rule.

In November 2016, the Bureau of Land Management (“BLM”) issued a final rule to further restrict venting and/or flaring of gas from facilities subject to BLM jurisdiction, and to modify certain royalty requirements. BLM issued a two-year stay of these requirements in December 2017. In September 2018, BLM published a final rule to rescind substantial portions of the rule. The rescission was challenged by multiple parties in the U.S. District Court for the Northern District of California. If the judicial challenges to the rule are successful and the rule were to come back into effect, the requirements would result in additional costs of compliance as well as increased monitoring, recordkeeping and recording for some of our facilities.

#### Hydraulic Fracturing

Hydraulic fracturing is a commonly used process that involves injecting water, sand and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Our business uses this technique extensively throughout our operations. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements. Various state and local-level initiatives in regions with substantial shale resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing.

#### Water

In 2014, the EPA and the U.S. Army Corps of Engineers published proposed regulations which expand the surface waters that are regulated under the federal Clean Water Act (“CWA”) and its various programs. While these regulations were finalized largely as proposed in 2015, the rule has been stayed by the courts pending a substantive decision on the merits. In December 2018, EPA and the Army Corps of Engineers issued a proposed rule that, if finalized, would amend the 2015 regulations to narrow the scope of federal CWA jurisdiction. If the new proposed rule is not finalized and the 2015 rule is ultimately implemented, the expansion of CWA jurisdiction will result in additional costs of compliance as well as increased monitoring, recordkeeping and recording for some of our facilities.

For additional information, see [Item 1A. Risk Factors](#).

#### Concentrations of Credit Risk

We are exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. In 2018, sales to Valero Marketing and Supply and Flint Hills Resources and each of their respective affiliates, each accounted for approximately 11% of our total revenues. In 2017, sales to Vitol and each of their respective affiliates accounted for approximately 10% of our total revenues. In 2016, sales to Valero Marketing and Supply, Tesoro Petroleum, and Flint Hills Resources and each of their respective affiliates accounted for approximately 13%, 11% and 10% of our total revenues.

#### Trademarks, Patents and Licenses

We currently hold U.S. and foreign patents. Although in the aggregate our trademarks and patents are important to us, we do not regard any single trademark, patent, or group of related trademarks or patents as critical or essential to our business as a whole.

#### Employees

We had approximately 2,400 active, full-time employees as of December 31, 2018.



Executive Officers of the Registrant

The executive officers of Marathon Oil and their ages as of February 1, 2019, are as follows:

Lee M. Tillman	57	Chairman, President and Chief Executive Officer
Dane E. Whitehead	57	Executive Vice President and Chief Financial Officer
T. Mitch Little	55	Executive Vice President—Operations
Reginald D. Hedgebeth	51	Senior Vice President, General Counsel and Secretary
Patrick J. Wagner	54	Executive Vice President—Corporate Development and Strategy
Gary E. Wilson	57	Vice President, Controller and Chief Accounting Officer

Mr. Tillman was appointed by the board of directors as chairman of the board effective February 1, 2019. In August 2013 he was appointed as president and chief executive officer. Prior to this appointment, Mr. Tillman served as vice president of engineering for ExxonMobil Development Company (a project design and execution company), where he was responsible for all global engineering staff engaged in major project concept selection, front-end design and engineering. Between 2007 and 2010, Mr. Tillman served as North Sea production manager and lead country manager for subsidiaries of ExxonMobil in Stavanger, Norway. Mr. Tillman began his career in the oil and gas industry at Exxon Corporation in 1989 as a research engineer and has extensive operations management and leadership experience.

Mr. Whitehead was appointed executive vice president and chief financial officer in March 2017. Prior to this appointment, Mr. Whitehead served as executive vice president and chief financial officer of both EP Energy Corp. and EP Energy LLC (oil and natural gas producer) since May 2012. Between 2009 and 2012 Mr. Whitehead served as senior vice president of strategy and enterprise business development and a member of El Paso Corporation's executive committee. He joined El Paso Exploration & Production Company as senior vice president and chief financial officer in 2006. Before joining El Paso Mr. Whitehead was vice president, controller and chief accounting officer of Burlington Resources Inc. (oil and natural gas producer), and formerly senior vice president and CFO of Burlington Resources Canada.

Mr. Little was appointed executive vice president of operations in August 2016 after having served as vice president, conventional since December 2015, vice president international and offshore exploration and production operations since September 2013, and as vice president, international production operations since September 2012. Prior to that, Mr. Little was resident manager of our Norway operations and served as general manager, worldwide drilling and completions. Mr. Little joined Marathon Oil in 1986 and has since held a number of engineering and management positions of increasing responsibility.

Mr. Hedgebeth was appointed senior vice president, general counsel and secretary in April 2017. Between 2009 and 2017 Mr. Hedgebeth served as general counsel, corporate secretary and chief compliance officer for Spectra Energy Corp (oil and natural gas pipeline company) and general counsel for Spectra Energy Partners, LP. Before joining Spectra Energy Mr. Hedgebeth served as senior vice president, general counsel and secretary with Circuit City Stores, Inc. (consumer electronics retail company), and vice president of legal for The Home Depot, Inc. (home improvement retail company).

Mr. Wagner was appointed executive vice president of corporate development and strategy in November 2017 after having served as senior vice president of corporate development and strategy since March 2017, vice president of corporate development and interim chief financial officer since August 2016 and vice president of corporate development since April 2014. Prior to this appointment, he served as senior vice president, western business unit, for QR Energy LP (an oil and natural gas producer) and the affiliated Quantum Resources Management, which he joined in early 2012 as vice president, exploration. Prior to that, Mr. Wagner was managing director in Houston for Scotia Waterous, the oil and gas arm of Scotiabank (an international banking services provider), from 2010 to 2012. Before joining Scotia, Mr. Wagner was vice president, Gulf of Mexico, for Devon Energy Corp. (an oil and natural gas producer), having joined Devon in 2003 as manager, international exploitation.

Mr. Wilson was appointed vice president, controller and chief accounting officer in October 2014. Prior to joining Marathon Oil, he served in various finance and accounting positions of increasing responsibility at Noble Energy, Inc. (a global exploration and production company) since 2001, including as director corporate accounting from February 2014 through September 2014, director global operations services finance from October 2012 through February 2014, director controls and reporting from April 2011 through September 2012, and international finance manager from

September 2009 through March 2011.

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#### Available Information

Our website is [www.marathonoil.com](http://www.marathonoil.com). Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K and other reports and filings with the SEC are available free of charge on our website as soon as reasonably practicable after the reports are filed or furnished with the SEC. Information contained on our website is not incorporated into this Annual Report on Form 10-K or our other securities filings. Our filings are also available in hard copy, free of charge, by contacting our Investor Relations office. Additionally, the SEC maintains a website ([www.sec.gov](http://www.sec.gov)) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Additionally, we make available free of charge on our website:

- our Code of Business Conduct and Code of Ethics for Senior Financial Officers;
- our Corporate Governance Principles; and
- the charters of our Audit and Finance Committee, Compensation Committee, Corporate Governance and Nominating Committee and Health, Environmental, Safety and Corporate Responsibility Committee.

#### Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the foregoing pages under "Disclosures Regarding Forward-Looking Statements" and other information included and incorporated by reference into this Annual Report on Form 10-K.

A substantial decline in crude oil and condensate, NGLs and natural gas prices would reduce our operating results and cash flows and could adversely impact our future rate of growth and the carrying value of our assets.

The markets for crude oil and condensate, NGLs and natural gas have been volatile and are likely to continue to be volatile in the future, causing prices to fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil and condensate, NGLs and natural gas. Many of the factors influencing prices of crude oil and condensate, NGLs and natural gas are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for crude oil and condensate, NGLs and natural gas;
- the cost of exploring for, developing and producing crude oil and condensate, NGLs and natural gas;
- the ability of the members of OPEC and certain non-OPEC members, such as Russia, to agree to and maintain production controls;
- the production levels of non-OPEC countries, including production levels in the shale plays in the United States;
- the level of drilling, completion and production activities by other exploration and production companies, and variability therein, in response to market conditions;
- political instability or armed conflict in oil and natural gas producing regions;
- changes in weather patterns and climate;
- natural disasters such as hurricanes and tornadoes;
- the price and availability of alternative and competing forms of energy;
- the effect of conservation efforts;
- epidemics or pandemics;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxes; and
- general economic conditions worldwide.

The long-term effects of these and other factors on the prices of crude oil and condensate, NGLs and natural gas are uncertain. Historical declines in commodity prices have adversely affected our business by:

- reducing the amount of crude oil and condensate, NGLs and natural gas that we can produce economically;
- reducing our revenues, operating income and cash flows;
- causing us to reduce our capital expenditures, and delay or postpone some of our capital projects;

- requiring us to impair the carrying value of our assets;
- reducing the standardized measure of discounted future net cash flows relating to crude oil and condensate, NGLs and natural gas; and
- increasing the costs of obtaining capital, such as equity and short- and long-term debt.

Estimates of crude oil and condensate, NGLs and natural gas reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions or other factors affecting those assumptions could impair the quantity and value of our reserves.

The proved reserve information included in this Annual Report on Form 10-K has been derived from engineering and geoscience estimates. Estimates of crude oil and condensate, NGLs, natural gas and our historical synthetic crude oil reserves were prepared, in accordance with SEC regulations, by our in-house teams of reservoir engineers and geoscience professionals and were reviewed and approved by our Corporate Reserves Group and third-party consultants. Reserves were valued based on SEC pricing for the periods ended December 31, 2018, 2017 and 2016, as well as other conditions in existence at those dates. The table below provides the 2018 SEC pricing for certain benchmark prices:

	2018 SEC Pricing
WTI Crude oil (per bbl)	\$ 65.56
Henry Hub natural gas (per mmbtu)	\$ 3.05
Brent crude oil (per bbl)	\$ 72.70
Mont Belvieu NGLs (per bbl)	\$ 26.63

If annual SEC crude oil benchmark prices (see table above) were to decrease to approximately \$45 per bbl, or 30% below average prices used to estimate 2018 proved reserves, we would not expect price related reserve revisions to have a material impact on proved reserve volumes. Future reserve revisions could also result from changes in capital funding, drilling plans and governmental regulation, among other things.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of crude oil and condensate, NGLs and natural gas that cannot be directly measured. Estimates of economically producible reserves and of future net cash flows depend on a number of variable factors and assumptions, including:

- location, size and shape of the accumulation as well as fluid, rock and producing characteristics of the accumulation;
- historical production from the area, compared with production from other analogous producing areas;
- the assumed impacts of regulation by governmental agencies;
- assumptions concerning future operating costs, taxes, development costs and workover and repair costs; and
- industry economic conditions, levels of cash flows from operations and other operating considerations.

As a result, different petroleum engineers and geoscientists, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of proved reserves and future net cash flows based on the same available data. Because of the subjective nature of such reserve estimates, each of the following items may differ materially from the estimated amounts:

- the amount and timing of production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

If we are unsuccessful in acquiring or finding additional reserves, our future crude oil and condensate, NGLs and natural gas production would decline, thereby reducing our cash flows and results of operations and impairing our financial condition.

The rate of production from crude oil and condensate, NGLs and natural gas properties generally declines as reserves are depleted. Except to the extent we acquire interests in additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, optimize production performance or identify additional reservoirs not currently producing or secondary recovery reserves, our proved reserves will decline materially as crude oil and condensate, NGLs and natural gas are produced. Accordingly, to the extent we are not successful in replacing the crude oil and condensate, NGLs and natural gas we produce, our future revenues will decline. Creating and maintaining an inventory of prospects for future production depends on many factors, including:

- obtaining rights to explore for, develop and produce crude oil and condensate, NGLs and natural gas in promising areas;
- drilling success;
- the ability to complete projects timely and cost effectively;
- the ability to find or acquire additional proved reserves at acceptable costs; and
- the ability to fund such activity.

Future exploration and drilling results are uncertain and involve substantial costs.

Drilling for crude oil and condensate, NGLs and natural gas involves numerous risks, including the risk that we may not encounter commercially productive reservoirs. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- inflation in exploration and drilling costs;
- fires, explosions, blowouts or surface cratering;
- lack of, or disruption in, access to pipelines or other transportation methods; and
- shortages or delays in the availability of services or delivery of equipment.

If crude oil and condensate, NGLs and natural gas prices decrease, it could adversely affect the abilities of our counterparties to perform their obligations to us, including abandonment obligations, which could negatively impact our financial results.

We often enter into arrangements to conduct certain business operations, such as oil and gas exploration and production, or transportation of crude oil and condensate, NGLs and natural gas, with partners, co-working interest owners, and other counterparties in order to share risks associated with those operations. In addition, we market our products to a variety of purchasers. If commodity prices decrease, some of our counterparties may experience liquidity problems and may not be able to meet their financial and other obligations, including abandonment obligations, to us. The inability of our joint venture partners or co-working interest owners to fund their portion of the costs under our joint venture agreements and joint operating agreements, or the nonperformance by purchasers, contractors or other counterparties of their obligations to us, could negatively impact our operating results and cash flows.

If we are unable to complete capital projects at their expected costs and in a timely manner, or if the market conditions assumed in our project economics deteriorate, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Delays or cost increases related to capital spending programs involving drilling and completion activities, engineering, procurement and construction of facilities (including improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted internal rates of return and operating results. Delays in making required changes or upgrades to our facilities could subject us to fines or penalties as well as affect our ability to supply certain products we produce. Such delays or cost increases may arise as a result of unpredictable factors, many of which are beyond our control, including:

- denial of or delay in receiving requisite regulatory approvals and/or permits;



- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of components or construction materials;
- increased costs or operational delays resulting from shortages of water;
- adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of vendors or suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project's debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors or subcontractors.

Any one or more of these factors could have a significant impact on our capital projects.

Our offshore operations involve special risks that could negatively impact us.

Offshore operations present technological challenges and operating risks because of the marine environment.

Activities in offshore operations may pose risks because of the physical distance to oilfield service infrastructure and service providers. Environmental remediation and other costs resulting from spills or releases may result in substantial liabilities.

We may incur substantial capital expenditures and operating costs as a result of compliance with and changes in environmental, health, safety and security laws and regulations, and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Our businesses are subject to numerous laws, regulations and other requirements relating to the protection of the environment, including those relating to the discharge of materials into the environment such as the flaring of natural gas, waste management, pollution prevention, greenhouse gas emissions and the protection of endangered species as well as laws, regulations, and other requirements relating to public and employee safety and health and to facility security. We have incurred and may continue to incur capital, operating and maintenance, and remediation expenditures as a result of these laws, regulations, and other requirements. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products, our operating results will be adversely affected. The specific impact of these laws, regulations, and other requirements may vary depending on a number of factors, including the age and location of operating facilities and production processes. We may also be required to make material expenditures to modify operations, install pollution control equipment, perform site clean-ups or curtail operations that could materially and adversely affect our business, financial condition, results of operations and cash flows. We may become subject to liabilities that we currently do not anticipate in connection with new, amended or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination. In addition, any failure by us to comply with existing or future laws, regulations, and other requirements could result in civil penalties or criminal fines and other enforcement actions against us.

We believe it is likely that the scientific and political attention to issues concerning the extent, causes of and responsibility for climate change will continue, with the potential for further regulations that could affect our operations. Our operations result in greenhouse gas emissions. Currently, various legislative or regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of review, discussion or implementation in countries where we operate, including the U.S. and the European Union. Internationally, the United Nations Framework Convention on Climate Change finalized an agreement among 195 nations at the 21st Conference of the Parties in Paris with an overarching goal of preventing global temperatures from rising more than 2 degrees Celsius. The agreement includes provisions that every country take some action to lower emissions, but there is no legal requirement for how or by what amount emissions should be lowered. The EPA has also finalized regulations targeting new sources of methane emissions from the oil and gas industry. Finalization of new legislation, regulations or international agreements in the future could result in increased costs to operate and maintain our facilities, capital expenditures to install new emission controls at our facilities, and costs to administer and manage any potential greenhouse gas emissions or carbon trading or tax programs. These costs and capital expenditures could be material. Although uncertain, these developments could increase our costs, reduce the demand for crude oil and condensate, NGLs and natural gas, and create delays in our obtaining air pollution permits for new or modified facilities.

The potential adoption of federal, state and local legislative and regulatory initiatives related to hydraulic fracturing could result in increased compliance costs, operating restrictions or delays in the completion of oil and gas wells.

Hydraulic fracturing is a commonly used process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Our business uses this technique extensively throughout our U.S. operations. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements. Various state and local-level initiatives in regions with substantial shale resources have been or may be proposed or implemented to further



regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. In 2015 the BLM issued a rule governing certain hydraulic fracturing practices on lands within their jurisdiction; however, this rule was rescinded in December 2017. This rescission is being judicially challenged before the U.S. District Court for the Northern District of California.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of crude oil and condensate, NGLs and natural gas, including from the shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs which could increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells.

The potential adoption of federal, state and local legislative and regulatory initiatives intended to address potential induced seismic activity in the areas in which we operate could result in increased compliance costs, operating restrictions or delays in the completion of oil and gas wells.

State and federal regulatory agencies have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. When caused by human activity, such events are called induced seismicity. Separate and apart from the referenced potential connection between injection wells and seismicity, concerns have been raised that hydraulic fracturing activities may be correlated to anomalous seismic events. Marathon uses hydraulic fracturing techniques throughout its U.S. operations.

While the scientific community and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity, some state regulatory agencies have modified their regulations or guidance to mitigate potential causes of induced seismicity. For example, Oklahoma has taken numerous regulatory actions in response to concerns related to the operation of produced water disposal wells and induced seismicity, and has issued guidelines to operators in certain areas of the State curtailing injection of produced water due to seismic concerns. Marathon does not currently own or operate injection wells or contract for such services in these areas. Further, Oklahoma issued guidelines to operators for management of anomalous seismicity that may be related to hydraulic fracturing activities in the SCOOP/STACK area. In addition, a number of lawsuits have been filed in Oklahoma alleging damage from seismicity relating to disposal well operations. Marathon has not been named in any of those lawsuits.

Increased seismicity in Oklahoma or other areas could result in additional regulation and restrictions on our operations and could lead to operational delays or increased operating costs. Additional regulation and attention given to induced seismicity could also lead to greater opposition, including litigation, to oil and gas activities.

Our business could be negatively impacted by cyberattacks targeting our computer and telecommunications systems and infrastructure, or targeting those of our third-party service providers.

Our business, like other companies in the oil and gas industry, has become increasingly dependent on digital technologies, including technologies that are managed by third-party service providers on whom we rely to help us collect, host or process information. Such technologies are integrated into our business operations and used as a part of our production and distribution systems in the U.S. and abroad, including those systems used to transport production to market, to enable communications, and to provide a host of other support services for our business. Use of the internet and other public networks for communications, services, and storage, including "cloud" computing, exposes all users (including our business) to cybersecurity risks.

While we and our third-party service providers commit resources to the design, implementation, and monitoring of our information systems, there is no guarantee that our security measures will provide absolute security. Despite these security measures, we may not be able to anticipate, detect, or prevent cyberattacks, particularly because the methodologies used by attackers change frequently or may not be recognized until launched, and because attackers are increasingly using techniques designed to circumvent controls and avoid detection. We and our third-party service

providers may therefore be vulnerable to security events that are beyond our control, and we may be the target of cyber-attacks, as well as physical attacks, which could result in information security breaches and significant disruption to our business. Our information systems and related infrastructure have experienced attempted and actual minor breaches of our cybersecurity in the past, but we have not suffered any losses or breaches which had a material effect on our business, operations or reputation relating to such attacks; however, there is no assurance that we will not suffer such losses or breaches in the future.

As cyberattacks continue to evolve, we may be required to expend significant additional resources to respond to cyberattacks, to continue to modify or enhance our protective measures, or to investigate and remediate any information

systems and related infrastructure security vulnerabilities. We may also be subject to regulatory investigations or litigation relating from cybersecurity issues.

Our level of indebtedness may limit our liquidity and financial flexibility.

As of December 31, 2018, our total debt was \$5.5 billion, with our next debt maturity in the amount of \$600 million due in 2020. Our indebtedness could have important consequences to our business, including, but not limited to, the following:

- we may be more vulnerable to general adverse economic and industry conditions;
- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- our flexibility in planning for, or reacting to, changes in our industry may be limited;
- a financial covenant in our Credit Agreement stipulates that our total debt to capitalization ratio will not exceed 65% as of the last day of any fiscal quarter, and if exceeded, may make additional borrowings more expensive and affect our ability to plan for and react to changes in the economy and our industry;
- we may be at a competitive disadvantage as compared to similar companies that have less debt; and
- additional financing in the future for working capital, capital expenditures, acquisitions or development activities, general corporate or other purposes may have higher costs and more restrictive covenants.

We may incur additional debt in order to fund our capital expenditures, acquisitions or development activities, or for general corporate or other purposes. A higher level of indebtedness increases the risk that our financial flexibility may deteriorate. Our ability to meet our debt obligations and service our debt depends on future performance. General economic conditions, crude oil and condensate, NGLs and natural gas prices, and financial, business and other factors will affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt. See Item 8. Financial Statements and Supplementary Data – Note 16 to the consolidated financial statements for a discussion of debt obligations. A downgrade in our credit rating could negatively impact our cost of and ability to access capital, which could adversely affect our business.

We receive debt ratings from the major credit rating agencies in the United States. Due to the volatility in crude oil and U.S. natural gas prices in recent years, credit rating agencies review companies in the energy industry periodically, including us. At December 31, 2018, our corporate credit ratings were: Standard & Poor's Global Ratings Services BBB- (positive); Fitch Ratings BBB (stable); and Moody's Investor Services, Inc. Ba1 (positive). The credit rating process is contingent upon a number of factors, many of which are beyond our control. A downgrade of our credit ratings could negatively impact our cost of capital and our ability to access the capital markets, increase the interest rate and fees we pay on our revolving credit facility, and may limit or reduce credit lines with our bank counterparties. We could also be required to post letters of credit or other forms of collateral for certain contractual obligations, which could increase our costs and decrease our liquidity or letter of credit capacity under our unsecured revolving credit facility. Limitations on our ability to access capital could adversely impact the level of our capital spending budget, our ability to manage our debt maturities, or our flexibility to react to changing economic and business conditions.

Our commodity price risk management activities may prevent us from fully benefiting from commodity price increases and may expose us to other risks, including counterparty risk.

Global commodity prices are volatile. In order to mitigate commodity price volatility and increase the predictability of cash flows related to the marketing of our crude oil and natural gas, we, from time to time, enter into crude oil and natural gas hedging arrangements with respect to a portion of our expected production. While hedging arrangements are intended to mitigate commodity price volatility, we may be prevented from fully realizing the benefits of price increases above the price levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements 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. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Worldwide political and economic developments and changes in law or policy could adversely affect our operations and materially reduce our profitability and cash flows.

Local political and economic factors in global markets could have a material adverse effect on us. A total of 29% of our crude oil and condensate, NGLs and natural gas related to continuing operations in 2018 was derived from production outside the U.S. and 16% of our proved reserves of crude oil and condensate, NGLs and natural gas as of December 31, 2018 were located outside the U.S. We are, therefore, subject to the political, geographic and economic risks and possible terrorist

activities or other armed conflict attendant to doing business within or outside of the U.S. There are many risks associated with operations in countries such as E.G., and the Kurdistan Region of Iraq including:

- changes in governmental policies relating to crude oil and condensate, NGLs or natural gas and taxation;
- other political, economic or diplomatic developments and international monetary fluctuations;
- political and economic instability, war, acts of terrorism, armed conflict and civil disturbances;
- the possibility that a government may seize our property with or without compensation, may attempt to renegotiate or revoke existing contractual arrangements or may impose additional taxes or royalty burdens; and
- fluctuating currency values, hard currency shortages and currency controls.

Changes in the U.S. or global political and economic environment or any U.S. or global hostility or the occurrence or threat of future terrorist attacks, or other armed conflict, could adversely affect the economies of the U.S. and other developed countries. A lower level of economic activity could result in a decline in energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects. These risks could lead to increased volatility in prices for crude oil and condensate, NGLs and natural gas. In addition, these risks could increase instability in the financial and insurance markets and make it more difficult for us to access capital and to obtain the insurance coverage that we consider adequate. These risks could also cause damage to, or the inability to access production facilities or other operating assets and could limit our service and equipment providers from delivering items necessary for us to conduct our operations.

Actions of governments through tax legislation or interpretations of tax law, and other changes in law, executive order and commercial restrictions could reduce our operating profitability, both in the U.S. and abroad. The U.S. government can prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries and will continue to do so in the future. Changes in law could also adversely affect our results, including new regulations resulting in higher costs to transport our production by pipeline, rail car, truck or vessel or the adoption of government payment transparency regulations that could require us to disclose competitively sensitive commercial information or that could cause us to violate the non-disclosure laws of other countries.

Our operations may be adversely affected by pipeline, rail and other transportation capacity constraints. The marketability of our production depends in part on the availability, proximity, and capacity of pipeline facilities, rail cars, trucks and vessels. If any pipelines, rail cars, trucks or vessels become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport our crude oil and condensate, NGLs and natural gas, which could increase the costs and/or reduce the revenues we might obtain from the sale of our production. Both the cost and availability of pipelines, rail cars, trucks, or vessels to transport our crude oil could be adversely impacted by new and expected state or federal regulations relating to transportation of crude oil.

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. We typically seek the acquisition of crude oil and natural gas properties and leases. Although we perform reviews of properties to be acquired in a manner that we believe is diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor may they permit us to become sufficiently familiar with the properties in order to fully assess possible deficiencies and potential problems. Even when problems with a property are identified, we often assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements. Moreover, there are numerous uncertainties inherent in estimating quantities of crude oil and natural gas (as previously discussed), 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 operate in a highly competitive industry, and many of our competitors are larger and have available resources in excess of our own.

The oil and gas industry is highly competitive, and many competitors, including major integrated and independent oil and gas companies, as well as national oil companies, are larger and have substantially greater resources at their disposal than we do. We compete with these companies for the acquisition of oil and natural gas leases and other properties. We also compete with these companies for equipment and personnel, including petroleum engineers, geologists, geophysicists and other specialists, required to develop and operate those properties and in the marketing of crude oil and condensate, NGLs and natural

gas to end-users. Such competition can significantly increase costs and affect the availability of resources, which could provide our larger competitors a competitive advantage when acquiring equipment, leases and other properties. They may also be able to use their greater resources to attract and retain experienced personnel. Many of our major projects and operations are conducted jointly with other parties, which may decrease our ability to manage risk.

We often enter into arrangements to conduct certain business operations, such as oil and gas exploration and production with other parties in order to share risks associated with those operations. However, these arrangements also may decrease our ability to manage risks and costs, particularly where we are not the operator. We could have limited influence over and control of the behaviors and performance of these operations. In addition, misconduct, fraud, noncompliance with applicable laws and regulations or improper activities by or on behalf of one or more of our partners or co-working interest owners could have a significant negative impact on our business and reputation. Our operations are subject to business interruptions and casualty losses. We do not insure against all potential losses and therefore we could be seriously harmed by unexpected liabilities and increased costs.

Our United States and International operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, spills, tornadoes, hurricanes and other adverse weather, tsunamis, earthquakes, volcanic eruptions or nuclear or other disasters, labor disputes and accidents. These same risks can be applied to the third-parties which transport our products from our facilities. A prolonged disruption in the ability of any pipelines, rail cars, trucks, or vessels to transport our production could contribute to a business interruption or increase costs. Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. These hazards could result in serious personal injury or loss of human life, significant damage to property and equipment, environmental pollution, impairment of operations and substantial losses to us. Various hazards have adversely affected us in the past, and damages resulting from a catastrophic occurrence in the future involving us or any of our assets or operations may result in our being named as a defendant in one or more lawsuits asserting potentially large claims or in our being assessed potentially substantial fines by governmental authorities. We maintain insurance against many, but not all, potential losses or liabilities arising from operating hazards in amounts that we believe to be prudent. Uninsured losses and liabilities arising from operating hazards could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Historically, we have maintained insurance coverage for physical damage including at times resulting business interruption to our major onshore and offshore facilities, with significant self-insured retentions. In the future, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for our insurance policies will change over time and could escalate. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, due to historical hurricane activity, the availability of insurance coverage for windstorms has changed and, in some instances, it is uneconomical. As a result, our exposure to losses from future windstorm activity has increased.

Litigation by private plaintiffs or government officials or entities could adversely affect our performance.

We currently are defending litigation and anticipate that we will be required to defend new litigation in the future. The subject matter of such litigation may include releases of hazardous substances from our facilities, privacy laws, contract disputes, royalty disputes or any other laws or regulations that apply to our operations. In some cases the plaintiff or plaintiffs seek alleged damages involving large classes of potential litigants, and may allege damages relating to extended periods of time or other alleged facts and circumstances. If we are not able to successfully defend such claims, they may result in substantial liability. We do not have insurance covering all of these potential liabilities. In addition to substantial liability, litigation may also seek injunctive relief which could have an adverse effect on our future operations.

For instance, government entities and other groups have filed lawsuits in several states seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions attributable to those fuels. The lawsuits allege damages as a result of global warming and the plaintiffs are seeking unspecified damages and abatement under various tort theories. Marathon Oil has been named as a defendant in several of these lawsuits, along with numerous other companies. Similar lawsuits may be filed in other jurisdictions. The ultimate outcome and impact to us cannot be predicted with certainty, and we could incur substantial legal costs associated

with defending these and similar lawsuits in the future.

In connection with our separation from MPC, MPC agreed to indemnify us for certain liabilities. However, there can be no assurance that the indemnity will be sufficient to protect us against the full amount of such liabilities, or that MPC's ability to satisfy its indemnification obligations will not be impaired in the future.



Pursuant to the Separation and Distribution Agreement and the Tax Sharing Agreement we entered into with MPC in connection with the spin-off, MPC agreed to indemnify us for certain liabilities. However, third parties could seek to hold us responsible for any of the liabilities that MPC agreed to retain or assume, and there can be no assurance that the indemnification from MPC will be sufficient to protect us against the full amount of such liabilities, or that MPC will be able to fully satisfy its indemnification obligations. In addition, even if we ultimately succeed in recovering from MPC any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves. The spin-off could result in substantial tax liability.

We obtained a private letter ruling from the IRS substantially to the effect that the distribution of shares of MPC common stock in the spin-off qualified as tax free to MPC, us and our stockholders for U.S. federal income tax purposes under Sections 355 and 368 and related provisions of the U.S. Internal Revenue Code of 1986, as amended (the "Code"). If the factual assumptions or representations made in the request for the private letter ruling prove to have been inaccurate or incomplete in any material respect, then we will not be able to rely on the ruling. Furthermore, the IRS does not rule on whether a distribution such as the spin-off satisfies certain requirements necessary to obtain tax-free treatment under Section 355 of the Code. Rather, the private letter ruling was based on representations by us that those requirements were satisfied, and any inaccuracy in those representations could invalidate the ruling. In connection with the spin-off, we also obtained an opinion of outside counsel, substantially to the effect that, the distribution of shares of MPC common stock in the spin-off qualified as tax free to MPC, us and our stockholders for U.S. federal income tax purposes under Sections 355 and 368 and related provisions of the Code. The opinion relied on, among other things, the continuing validity of the private letter ruling and various assumptions and representations as to factual matters made by MPC and us which, if inaccurate or incomplete in any material respect, would jeopardize the conclusions reached by such counsel in its opinion. The opinion is not binding on the IRS or the courts, and there can be no assurance that the IRS or the courts would not challenge the conclusions stated in the opinion or that any such challenge would not prevail.

If, notwithstanding receipt of the private letter ruling and opinion of counsel, the spin-off were determined not to qualify under Section 355 of the Code, each U.S. holder of our common stock who received shares of MPC common stock in the spin-off would generally be treated as receiving a taxable distribution of property in an amount equal to the fair market value of the shares of MPC common stock received. That distribution would be taxable to each such stockholder as a dividend to the extent of our accumulated earnings and profits as of the effective date of the spin-off. For each such stockholder, any amount that exceeded those earnings and profits would be treated first as a non-taxable return of capital to the extent of such stockholder's tax basis in its shares of our common stock with any remaining amount being taxed as a capital gain. We would be subject to tax as if we had sold all the outstanding shares of MPC common stock in a taxable sale for their fair market value and would recognize taxable gain in an amount equal to the excess of the fair market value of such shares over our tax basis in such shares.

Under the terms of the Tax Sharing Agreement we entered into with MPC in connection with the spin-off, MPC is generally responsible for any taxes imposed on MPC or us and our subsidiaries in the event that the spin-off and/or certain related transactions were to fail to qualify for tax-free treatment as a result of actions taken, or breaches of representations and warranties made in the Tax Sharing Agreement, by MPC or any of its affiliates. However, if the spin-off and/or certain related transactions were to fail to qualify for tax-free treatment because of actions or failures to act by us or any of our affiliates, we would be responsible for all such taxes.

We may issue preferred stock whose terms could dilute the voting power or reduce the value of Marathon Oil common stock.

Our restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such preferences, powers and relative, participating, optional and other rights, including preferences over Marathon Oil common stock respecting dividends and distributions, as our Board of Directors generally may determine. The terms of one or more classes or series of preferred stock could dilute the voting power or reduce the value of Marathon Oil common stock. For example, we could grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we could assign to holders of preferred stock could affect the residual value of the common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and general character of our principal crude oil and condensate, NGLs and natural gas properties and facilities, and other important physical properties have been described by segment under Item 1. Business.

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Estimated net proved crude oil and condensate, NGLs and natural gas reserves and the basis for estimating these reserves are set forth in Item 8. Financial Statements and Supplementary Data – Supplementary Information on Oil and Gas Producing Activities.

#### Item 3. Legal Proceedings

We are a defendant in a number of legal and administrative proceedings arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims, tax disputes and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. See Item 8. Financial Statements and Supplementary Data – Note 25 to the consolidated financial statements for a description of such legal and administrative proceedings.

#### Environmental Proceedings

The following is a summary of certain proceedings involving us that were pending or contemplated as of December 31, 2018, under federal and state environmental laws.

Government entities have filed lawsuits in several states seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions attributable to those fuels. The lawsuits allege damages as a result of global warming and the plaintiffs are seeking unspecified damages and abatement under various tort theories. Marathon Oil has been named as a defendant in several of these lawsuits, along with numerous other companies. Similar lawsuits may be filed in other jurisdictions. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the claims made against us are without merit and will not have a material adverse effect on our consolidated financial position, results of operations or cash flow.

As of December 31, 2018, we have sites across the country where remediation is being sought under environmental statutes, both federal and state, or where private parties are seeking remediation through discussions or litigation.

Based on currently available information the accrued amount to address the clean-up and remediation costs connected with these sites is not material.

If our assumptions relating to these costs prove to be inaccurate, future expenditures may exceed our accrued amounts.

#### Item 4. Mine Safety Disclosures

Not applicable.

## PART II

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

The principal market on which Marathon Oil common stock is traded is the New York Stock Exchange ("NYSE"), and is traded under the trading symbol 'MRO'. As of January 31, 2019, there were 29,960 registered holders of Marathon Oil common stock.

Dividends – Our Board of Directors intends to declare and pay dividends on Marathon Oil common stock based on our financial condition and results of operations, although it has no obligation under Delaware law or the Restated Certificate of Incorporation to do so. In determining our dividend policy, the Board will rely on our consolidated financial statements. Dividends on Marathon Oil common stock are limited to our legally available funds.

The following table provides information about purchases by Marathon Oil and its affiliated purchaser, during the quarter ended December 31, 2018, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934:

Period	Total Number of Shares Purchased <sup>(a)</sup>	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs <sup>(b)</sup>	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs <sup>(b)</sup>
10/01/18 – 10/31/18	187,151,077	\$ 21.52	7,110,719	\$ 1,009,043,095
11/01/18 – 11/30/18	186,260,834	\$ 16.74	6,256,479	\$ 904,286,215
12/01/18 – 12/31/18	186,593,370	\$ 15.78	6,592,195	\$ 800,286,037
Total	20,005,281	\$ 18.13	19,959,393	

<sup>(a)</sup> 45,888 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

<sup>(b)</sup> In January 2006, we announced a \$2.0 billion share repurchase program. Our Board of Directors subsequently increased the authorization for repurchases under the program by \$500 million in January 2007, by \$500 million in May 2007, by \$2.0 billion in July 2007, and by \$1.2 billion in December 2013, for a total authorized amount of \$6.2 billion.

As of December 31, 2018, we have repurchased 157 million common shares at a cost of approximately \$5.4 billion, excluding transaction fees and commissions. Of this total, approximately 20 million shares were acquired at a cost of approximately \$362 million during the fourth quarter of 2018. The remaining share repurchase authorization as of December 31, 2018 is approximately \$800 million. Purchases under the program are made at our discretion and may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. Shares repurchased as of December 31, 2018 were held as treasury stock.

## Item 6. Selected Financial Data

(In millions, except per share data)	Year Ended December 31,				
	2018	2017	2016	2015	2014
Statement of Income Data <sup>(a)(b)(c)</sup>					
Total revenues and other income	\$6,582	\$4,765	\$3,787	\$4,953	\$9,646
Income (loss) from continuing operations	1,096	(830 )	(2,087 )	(1,701 )	710
Discontinued operations	—	(4,893 )	(53 )	(503 )	2,336
Net income (loss)	1,096	(5,723 )	(2,140 )	(2,204 )	3,046
Per Share Data <sup>(a)(b)(c)</sup>					
Basic:					
Income (loss) from continuing operations	\$1.30	\$(0.97 )	\$(2.55 )	\$(2.51 )	\$1.04
Discontinued operations	\$—	\$(5.76 )	\$(0.06 )	\$(0.75 )	\$3.44
Net income (loss)	\$1.30	\$(6.73 )	\$(2.61 )	\$(3.26 )	\$4.48
Diluted:					
Income (loss) from continuing operations	\$1.29	\$(0.97 )	\$(2.55 )	\$(2.51 )	\$1.04
Discontinued operations	\$—	\$(5.76 )	\$(0.06 )	\$(0.75 )	\$3.42
Net income (loss)	\$1.29	\$(6.73 )	\$(2.61 )	\$(3.26 )	\$4.46
Statement of Cash Flows Data <sup>(b)</sup>					
Additions to property, plant and equipment related to continuing operations	\$(2,753 )	\$(1,974 )	\$(1,204 )	\$(3,485 )	\$(4,937 )
Dividends paid	169	170	162	460	543
Dividends per share	\$0.20	\$0.20	\$0.20	\$0.68	\$0.80
Balance Sheet Data at December 31					
Total assets	\$21,321	\$22,012	\$31,094	\$32,311	\$35,983
Total long-term debt, including capitalized leases	5,499	5,494	6,581	7,268	5,285

Includes impairments to producing properties of \$75 million, \$229 million, \$67 million, \$381 million and \$132 million in 2018, 2017, 2016, 2015 and 2014 and impairments to unproved properties of \$208 million, \$246 million,

<sup>(a)</sup> \$195 million, \$655 million and \$306 million in 2018, 2017, 2016, 2015 and 2014 (see Item 8. Financial Statements and Supplementary Data – Note 11 to the consolidated financial statements). Includes a goodwill impairment of \$340 million in 2015 related to the U.S. reporting unit.

We closed on the sale of our Canada business in 2017 which resulted in an after-tax non-cash impairment charge of \$4.96 billion and our Angola assets and Norway business in 2014 (see Item 8. Financial Statements and <sup>(b)</sup> Supplementary Data – Note 5 to the consolidated financial statements). The applicable periods have been recast to reflect as discontinued operations.

<sup>(c)</sup> December 31, 2016 includes the increase of a valuation allowance on certain of our deferred tax assets for \$1,346 million.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the information under Item 8. Financial Statements and Supplementary Data and the other financial information found elsewhere in this Form 10-K. The following discussion includes forward-looking statements that involve certain risks and uncertainties. See "Disclosures Regarding Forward-Looking Statements" (immediately prior to Part I) and Item 1A. Risk Factors.

Each of our two reportable operating segments are organized by geographic location and managed according to the nature of the products and services offered.

• **United States** – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States;

• **International** – explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of the United States and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

### Executive Overview

During 2018, we continued our outstanding operational execution and capital efficiency across our multi-basin U.S. portfolio, maintained a strong balance sheet and delivered solid financial results. Total proved reserves were 1.3 billion boe and total assets were \$21.3 billion at December 31, 2018. Additionally in 2018, we closed on the sale of our subsidiary, Marathon Oil Libya Limited and entered into agreements to complete a full country exit in Kurdistan. Our 2018 financial and operating results highlighted below reflect our ongoing commitment to our core strategy of continuous corporate returns improvement, sustainable cash flow generation at conservative oil prices and the return of capital to shareholders.

Key highlights include the following:

#### Simplifying and concentrating our portfolio

• Early in 2018 we closed on the sale of our Libya subsidiary for proceeds of approximately \$450 million resulting in a gain of \$255 million and received \$750 million in remaining proceeds from the sale of our Canadian business.

• During 2018 we entered into agreements for the sale of our interest in the non-operated Sarsang and Atrush blocks which will complete our full country exit from Kurdistan. We expect the remaining transaction for our subsidiary Marathon Oil KDV B.V., which holds our non-operated interest in the Atrush block, to close in the first half of 2019.

• In July 2018 we closed on the sale of non-core, non-operated conventional assets in the U.S. segment for a pre-tax gain of \$32 million, including three in the Gulf of Mexico, further concentrating and simplifying our portfolio.

• In Northern Delaware we acquired 1,800 net acres in New Mexico for \$105 million from the Bureau of Land Management lease sale, which is synergistic with our existing footprint in the resource play.

• Captured approximately 260,000 net acres in the emerging Louisiana Austin Chalk play at a cost of less than \$850 per acre.

#### Strengthened balance sheet and liquidity

• Returned additional capital to shareholders in 2018 by acquiring 36 million of common shares at a cost of \$700 million, with \$800 million of repurchase authorization remaining.

• Reduced estimated costs of our asset retirement obligations by \$338 million primarily through accelerating our U.K. abandonment timing to capture favorable market conditions and through the disposition of Gulf of Mexico assets.

• Cash and cash equivalents increased approximately \$900 million as a result of the sale of our Libya subsidiary and the receipt of the remaining proceeds from the sale of our Canadian business.

• Cash provided by operating activities from continuing operations increased by 63%, compared to the same period last year, to \$3,234 million primarily as a result of increased price realizations and net sales volumes in our U.S. resource plays.

#### Financial and operational results

• Total net sales volumes for the year were 420 mboed, including 298 mboed in the U.S. Our U.S. net sales volumes increased 64 mboed and our wells to sales increased 18% compared to 2017.

• Added proved reserves of 186 mmbob for a reserve replacement ratio from continuing operations of 125%.

• Our net income per share from continuing operations was \$1.30 in 2018 as compared to a net loss per share of \$0.97 last year. Included in the 2018 net income are:



An increase in revenues of approximately 39% compared to 2017, as a result of increased price realizations of 28% and a 27% increase in net sales volumes in the United States.

Our net gain on disposal of assets increased in 2018 to \$319 million due to the sale of our Libya subsidiary for \$255 million.

Production expense, taxes other than income and shipping, handling and other increased 18%, 63% and 33%, during 2018 as a result of an increase in net sales volumes across our U.S. resource plays.

Exploration and impairment expenses decreased by \$274 million to \$364 million, year over year, primarily due to non-cash impairment charges on proved and unproved properties in 2017. See Item 8. Financial Statements and Supplementary Data - Note 11 to the consolidated financial statements for further detail.

#### Outlook

##### Capital Budget

On February 13, 2019 we announced our total 2019 Capital Budget of \$2.6 billion, which includes approximately \$2.4 billion of development capital and approximately \$200 million to fund resource play leasing and exploration ("REx"). Our \$2.4 billion development capital budget is 95% dedicated to the four U.S. resource plays with approximately 60% allocated to the Eagle Ford and Bakken and approximately 40% allocated to Oklahoma and the Northern Delaware. Our 2019 Capital Budget is broken down by reportable segment in the table below:

(In millions)	Capital Budget
United States <sup>(a)</sup>	\$ 2,525
International and corporate other <sup>(b)</sup>	75
Total Capital Budget	\$ 2,600

<sup>(a)</sup> Includes approximately \$200 million of spend to fund REX.

<sup>(b)</sup> International and corporate other includes our International segment and other corporate items.

#### Operations

Our net sales volumes increased 11% in 2018 primarily as a result of new wells to sales across all U.S. resource plays. The following table presents a summary of our sales volumes for each of our segments. Refer to the Results of Operations section for a price-volume analysis for each of the segments.

Net Sales Volumes	2018	Increase (Decrease)	2017	Increase (Decrease)	2016
United States (mboed)	298	27 %	234	5 %	223
International (mboed) <sup>(a)</sup>	122	(16 )%	145	19 %	122
Total continuing operations (mboed)	420	11 %	379	10 %	345

<sup>(a)</sup> We closed on the sale of our Libya subsidiary in the first quarter of 2018. Years ended December 31, 2018, 2017 and 2016 includes net sales volumes relating to Libya of 8 mboed, 20 mboed and 3 mboed.

#### United States

Net sales volumes in the segment were higher during the year ended December 31, 2018 primarily as a result of new wells to sales across all U.S. resource plays. The following tables provide additional details regarding net sales volumes, sales mix and operational drilling activity for our significant operations within this segment:

Net Sales Volumes	2018	Increase (Decrease)	2017	Increase (Decrease)	2016
Equivalent Barrels (mboed)					
Eagle Ford	108	7%	101	(4)%	105
Bakken	84	50%	56	4%	54
Oklahoma	74	37%	54	54%	35
Northern Delaware	20	233%	6	100%	—
Other United States <sup>(a)</sup>	12	(29)%	17	(41)%	29



Total United States (mboed) 298 27% 234 5% 223

(a) Year ended December 31, 2018 includes decreases of 5 mboed, relating primarily to the disposition of certain assets in the Gulf of Mexico and conventional assets in Oklahoma in July 2018 and September 2017 and Colorado in October 2017. Additionally, year ended December 31, 2017 includes decreases of 14 mboed, consisting of the disposition of Wyoming and certain non-operated CO2 and waterflood assets in West Texas and New Mexico in 2016. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions.

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Sales Mix - U.S. Resource Plays - 2018	Eagle Ford	Bakken	Oklahoma	Northern Delaware	Total
Crude oil and condensate	59%	85%	25%	58%	57%
Natural gas liquids	21%	8%	28%	20%	20%
Natural gas	20%	7%	47%	22%	23%

Drilling Activity - U.S. Resource Plays 2018 2017 2016

Gross Operated

Eagle Ford:

Wells drilled to total depth 123 182 168

Wells brought to sales 149 157 168

Bakken:

Wells drilled to total depth 78 90 3

Wells brought to sales 80 39 13

Oklahoma:

Wells drilled to total depth 55 86 33

Wells brought to sales 57 73 28

Northern Delaware:

Wells drilled to total depth 69 27 —

Wells brought to sales 52 18 —

Eagle Ford – Our net sales volumes were 108 mboed in 2018, which was 7% higher compared to 2017. We brought 149 gross company-operated wells to sales in 2018. In Atascosa County, we brought online 40 wells during 2018 with strong well results, demonstrating the strength of the extended core. During 2018, we generated significant cash flow, improved well productivity with annual oil growth of 7%, despite 5% fewer gross company-operated wells to sales.

Bakken – Our net sales volumes of 84 mboed in 2018 represented a 50% increase over the prior year of 56 mboed. We brought 80 gross company-operated wells to sales in 2018 with continued impressive well results. During 2018, we delivered best-in-basin well performance, significant cash flow, capital efficient annual oil growth of 53%, and successful core extension tests in the Ajax, Southern Hector and Elk Creek areas. During the fourth quarter we conducted a successful core extension test in the Ajax area of Dunn County, as the four-well Gloria pad achieved strong results at an average completed well cost of approximately \$5 million.

Oklahoma – Our net sales volumes in 2018 increased by 37% from 2017, with net sales volumes of 74 mboed. We brought 57 gross company-operated wells to sales in 2018. In 2018, we successfully transitioned to infill development in the over-pressured STACK Meramec and SCOOP Woodford, delivering competitive returns and predictable results at various spacing designs.

Northern Delaware – Our net sales volumes were 20 mboed in 2018 while bringing 52 gross company-operated wells to sales. We continue to make significant progress in improving efficiencies and midstream access for all products to protect and enhance margins. During the fourth quarter, we executed a comprehensive water management agreement covering the entire Red Hills prospect area, complementing a previously announced agreement in Eddy County.

## International

Net sales volumes in the segment were lower during the year ended December 31, 2018 primarily due to the sale of our subsidiary in Libya, planned maintenance activities and natural declines in E.G. The following table provides details regarding net sales volumes for our significant operations within this segment:

Net Sales Volumes	2018	Increase (Decrease)	2017	Increase (Decrease)	2016
Equivalent Barrels (mboed)					
Equatorial Guinea	97	(11)%	109	7%	102
United Kingdom <sup>(a)</sup>	13	(7)%	14	(18)%	17
Libya	8	(60)%	20	567%	3
Other International	4	100%	2	100%	—
Total International	122	(16)%	145	19%	122
Equity Method Investees					
LNG (mtd)	5,805	(10)%	6,423	9%	5,874
Methanol (mtd)	1,241	(10)%	1,374	1%	1,358
Condensate and LPG (boed)	13,034	(10)%	14,501	8%	13,430

<sup>(a)</sup> Includes natural gas acquired for injection and subsequent resale.

- Equatorial Guinea – Net sales volumes in 2018 were lower than 2017 as a result of timing of liftings, natural field decline and planned maintenance activities during the year.

United Kingdom – Net sales volumes in 2018 were slightly lower than 2017 primarily due to unscheduled downtime at the non-operated Foinaven complex in the fourth quarter 2018.

Libya – During the first quarter of 2018 we closed on the sale of our subsidiary in Libya. See Note 5 to the consolidated financial statements for further information.

## Market Conditions

Crude oil and condensate and NGLs benchmarks increased in 2018 as compared to the same period in 2017. As a result, we experienced increased price realizations associated with those benchmarks. We continue to expect crude oil and condensate, NGLs and natural gas benchmark prices to remain volatile based on global supply and demand, which will result in increases or decreases in our price realizations during 2019. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition – Critical Accounting Estimates for further discussion of how declines in commodity prices could impact us. Additional detail on market conditions, including our average price realizations and benchmarks for crude oil and condensate, NGLs and natural gas relative to our operating segments, follows.

## United States

The following table presents our average price realizations and the related benchmarks for crude oil and condensate, NGLs and natural gas for 2018, 2017 and 2016.

	2018	Increase (Decrease)		2017	Increase (Decrease)		2016
Average Price Realizations <sup>(a)</sup>							
Crude oil and condensate (per bbl) <sup>(b)</sup>	\$63.11	28 %		\$49.35	28 %		\$38.57
Natural gas liquids (per bbl)	24.54	19 %		20.55	56 %		13.15
Natural gas (per mcf) <sup>(c)</sup>	2.65	(7 )%		2.84	19 %		2.38
Benchmarks							
WTI crude oil average of daily prices (per bbl)	\$64.90	28 %		\$50.85	17 %		\$43.47
LLS crude oil average of daily prices (per bbl)	70.04	30 %		54.04	20 %		45.02
Mont Belvieu NGLs (per bbl) <sup>(d)</sup>	28.63	20 %		23.76	37 %		17.40
Henry Hub natural gas settlement date average (per mmbtu)	3.09	(1 )%		3.11	26 %		2.46

<sup>(a)</sup> Excludes gains or losses on commodity derivative instruments.

<sup>(b)</sup> Inclusion of realized gains (losses) would have impacted average price realizations by \$(4.60) per bbl, \$0.75 per bbl, and \$0.92 per bbl for 2018, 2017, and 2016.

<sup>(c)</sup> Inclusion of realized gains (losses) on natural gas derivative instruments would have a minimal impact on average price realizations for the periods presented.

<sup>(d)</sup> Bloomberg Finance LLP: Y-grade Mix NGL of 50% ethane, 25% propane, 10% butane, 5% isobutane and 10% natural gasoline.

Crude oil and condensate – Price realizations may differ from benchmarks due to the quality and location of the product.

Natural gas liquids – The majority of our sales volumes are at reference to Mont Belvieu prices.

Natural gas – A significant portion of volumes are sold at bid-week prices, or first-of-month indices relative to our producing areas.

## International

The following table presents our average price realizations and the related benchmark for crude oil for 2018, 2017 and 2016.

	2018	Increase (Decrease)		2017	Increase (Decrease)		2016
Average Price Realizations							
Crude oil and condensate (per bbl)	\$64.25	21 %		\$53.05	27 %		\$41.70
Natural gas liquids (per bbl)	2.27	(28 )%		3.15	49 %		2.11
Natural gas (per mcf)	0.54	(2 )%		0.55	6 %		0.52
Benchmark							
Brent (Europe) crude oil (per bbl) <sup>(a)</sup>	\$71.06	31 %		\$54.25	25 %		\$43.55

<sup>(a)</sup> Average of monthly prices obtained from the United States Energy Information Agency website.

## United Kingdom

Crude oil and condensate – Generally sold in relation to the Brent crude benchmark.

## Equatorial Guinea

Crude oil and condensate – Alba Field liquids production is primarily condensate and generally sold in relation to the Brent crude benchmark. Alba Plant LLC processes the rich hydrocarbon gas which is supplied by the Alba Field under a fixed price long term contract. Alba Plant LLC extracts NGL's and secondary condensate which is then sold by Alba Plant LLC at market prices, with our share of the revenue reflected in income from equity method investments on the consolidated statements of income.

Natural gas liquids – Wet gas is sold to Alba Plant LLC at a fixed-price term contract resulting in realized prices not fully tracking market price. Alba Plant LLC extracts NGLs, which are sold at market price, with our share of income from Alba Plant LLC being reflected in the income from equity method investments on the consolidated statements of

income.

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Natural gas - Dry natural gas is sold to EGHoldings and AMPCO at fixed-price long term contracts resulting in realized prices not fully tracking market price. We derive additional value from the equity investment in our downstream gas processing units EG LNG and AMPCO that market LNG and methanol at market prices.

#### Consolidated Results of Operations: 2018 compared to 2017

Revenues from contracts with customers are presented by segment in the table below:

(In millions)	Year Ended	
	December 31, 2018	December 31, 2017
Revenues from contracts with customers		
United States	\$4,886	\$3,093
International	1,016	1,154
Segment revenues from contracts with customers	\$5,902	\$4,247

Below is a price/volume analysis for each segment. Refer to the preceding Operations and Market Conditions sections for additional detail related to our net sales volumes and average price realizations.

(In millions)	Year Ended December 31, 2017	Increase (Decrease) Related to		Year Ended December 31, 2018
		Price Realizations	Net Sales Volumes	
United States Price/Volume Analysis				
Crude oil and condensate	\$ 2,402	\$861	\$ 684	\$ 3,947
Natural gas liquids	324	80	91	495
Natural gas	361	(30 )	82	413
Other sales	6			31
Total	\$ 3,093			\$ 4,886
International Price/Volume Analysis				
Crude oil and condensate	\$ 1,000	\$155	\$ (267 )	\$ 888
Natural gas liquids	15	(4 )	(2 )	9
Natural gas	97	(2 )	(9 )	86
Other sales	42			33
Total	\$ 1,154			\$ 1,016

Net loss on commodity derivatives decreased \$22 million in 2018 from 2017. We have multiple crude oil and natural gas derivative contracts indexed to NYMEX WTI and Henry Hub. We record commodity derivative gains/losses as the index pricing and forward curves change each period. See Note 14 to the consolidated financial statements for further information.

Marketing revenues decreased \$162 million in 2018 from 2017. This decrease is the result of adopting the new revenue standard, ASC Topic 606, Revenue from Contracts with Customers during the first quarter of 2018. As a result of this standard, we have changed our presentation of marketing revenues and marketing expenses from the historical gross presentation to a net presentation. See Note 2 to the consolidated financial statements for further information.

Income from equity method investments decreased \$31 million primarily due to higher production costs and lower volumes and pricing at our E.G. LNG production facility. Our higher production costs and lower volumes were primarily driven by planned maintenance activities during the first quarter 2018.

Net gain on disposal of assets increased \$261 million in 2018 from 2017. This increase was primarily related to the 2018 sale of our Libya subsidiary for a pre-tax gain of \$255 million; and also includes the sale of non-core assets in the Gulf of Mexico and our International segment during the current year. See Item 8. Financial Statements and

Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions. Other income increased \$72 million in 2018 from 2017 primarily a result of the reduction of our U.K. asset retirement obligation during 2018. See Item 8. Financial Statements and Supplementary Data - Note 12 to the consolidated financial statements for detail about our asset retirement obligation. Production expenses increased \$126 million during 2018 from 2017 primarily due to higher sales volumes across our United States segment. Our United States segment increased \$149 million primarily due to higher costs as a result of increased

sales volumes and new wells to sales in our developing Northern Delaware asset. International segment decreased \$24 million primarily due to the sale of our subsidiary in Libya in the first quarter 2018.

The following table provides production expense and production expense rates for each segment:

(in millions/\$ per boe)	2018		2017	
Production Expense and Production Expense Rate	Expense	Rate	Expense	Rate
United States	\$625	\$5.75	\$476	\$5.57
International	\$215	\$4.86	\$239	\$4.51

Marketing costs decreased \$168 million in 2018 from 2017. This decrease is the result of adopting the new revenue standard, ASC Topic 606, Revenue from Contracts with Customers during the first quarter of 2018. As a result of this standard, we have changed our presentation of marketing revenues and marketing expenses from the historical gross presentation to a net presentation. See [Note 2](#) to the consolidated financial statements for further information.

Shipping, handling and other operating expenses increased \$144 million in 2018 from 2017 primarily as a result of increased sales volumes in our United States segment.

Exploration expenses decreased \$120 million during 2018 versus the comparable 2017. The decrease was primarily due to lower unproved property impairments and dry well costs in certain non-core international properties in 2018 versus 2017. See Item 8. Financial Statements and Supplementary Data - [Note 11](#) to the consolidated financial statements for details of these items.

The following table summarizes the components of exploration expenses:

(In millions)	Year	
	Ended	December
	31,	31,
	2018	2017
Exploration Expenses		
Unproved property impairments	\$208	\$246
Dry well costs	47	77
Geological and geophysical	21	25
Other	13	61
Total exploration expenses	\$289	\$409

Depreciation, depletion and amortization increased \$69 million in 2018 from 2017 primarily as a result of an increase of \$206 million in the United States segment primarily due to higher sales volumes across all U.S. resource plays. Offsetting this higher expense was a decrease of \$131 million in our International segment primarily due to the reduction of our estimated U.K. asset retirement costs. Additionally, lower sales volumes in E.G., asset sales in Libya and Kurdistan all contributed to the lower expense during 2018. Our segments apply the units-of-production method to the majority of their assets, including capitalized asset retirement costs; therefore, volumes have an impact on DD&A expense.

The DD&A rate (expense per boe), which is impacted by field-level changes in reserves, capitalized costs and sales volumes, can also impact our DD&A expense. Our United States DD&A rate decreased in 2018 primarily due to increased proved developed reserves in our U.S. resource plays in late 2017; as well as reduced capitalized costs relating to the Gulf of Mexico impairment charge in 2017 and the subsequent sale of these assets in 2018. The DD&A rate for International decreased with the reduction of our estimated U.K. asset retirement costs in the second half of 2018 and 2017.

The following table provides DD&A rates for each segment:

(\$ per boe)	2018	2017
DD&A Rate		
United States	\$20.39	\$23.51
International	\$4.44	\$6.19

Impairments decreased \$154 million in 2018 from 2017. This decrease was primarily the result of the proved property impairments in the third quarter 2017 in certain non-core international properties and certain properties in the Gulf of Mexico. See Item 8. Financial Statements and Supplementary Data - [Note 11](#) to the consolidated financial



statement for detail of proved property impairments each year.

Taxes other than income tend to increase or decrease in relation to revenue and sales volumes, primarily in the U.S. As U.S. sales volumes and revenues increased during 2018, this resulted in an increase of \$116 million compared to 2017. Additionally, the State of Oklahoma approved an increase to the gross production tax from 2% to 5% on all existing and new wells for the first thirty-six months, effective July 1, 2018. The following table summarizes the components of taxes other than

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income:

	Year Ended December 31,	
(In millions)	2018	2017
Taxes other than income		
Production and severance	\$ 208	\$ 121
Ad valorem	23	13
Other	68	49
Total taxes other than income	\$ 299	\$ 183

General and administrative expenses increased \$23 million in 2018 compared to 2017. This was primarily the result of officer and non-officer compensation, including improved performance of stock-based performance units.

Net interest and other decreased \$44 million during 2018 compared to 2017. This decrease was primarily due the redemption of \$1.76 billion of debt during 2017, partially offset by the termination of our forward starting interest rate swaps in 2017, which resulted in a gain of \$46 million. The components of net interest and other are detailed in Item 8. Financial Statements and Supplementary Data - [Note 21](#) to the consolidated financial statements.

Loss on early extinguishment of debt decreased \$51 million in 2018 compared to 2017 primarily due to make-whole call provisions paid upon redemption of \$1.76 billion in senior unsecured notes in 2017. See Item 8. Financial Statements and Supplementary Data - [Note 16](#) to the consolidated financial statements for further detail.

Provision (benefit) for income taxes reflects an effective tax rate from continuing operations of 23% and 83% for 2018 and 2017. See Item 8. Financial Statements and Supplementary Data - [Note 8](#) to the consolidated financial statements for a discussion of the effective income tax rate.

Discontinued operations are presented net of tax. See Item 8. Financial Statements and Supplementary Data - [Note 5](#) to the consolidated financial statements for financial information concerning our discontinued operations.

Segment Results: 2018 compared to 2017

Segment Income (Loss)

Segment income (loss) represents income (loss) from continuing operations excluding certain items not allocated to operating segments, net of income taxes. A portion of our corporate and operations general and administrative support costs are not allocated to the operating segments. Gains or losses on dispositions, certain impairments, unrealized gains or losses on commodity derivative instruments, pension settlement losses, or other items (as determined by the CODM) are not allocated to operating segments.

The following table reconciles segment income (loss) to net income (loss):

	Year Ended December 31,	
(In millions)	2018	2017
United States	\$608	\$(148 )
International	473	374
Segment income (loss)	1,081	226
Items not allocated to segments, net of income taxes <sup>(a)</sup>	15	(1,056 )
Income (loss) from continuing operations	1,096	(830 )
Income (loss) from discontinued operations <sup>(b)</sup>	—	(4,893 )
Net income (loss)	\$1,096	\$(5,723)

<sup>(a)</sup> See Item 8. Financial Statements and Supplementary Data - [Note 7](#) to the consolidated financial statements for further detail about items not allocated to segments.

<sup>(b)</sup> We sold our Canadian business in the second quarter of 2017. The Canadian business is reflected as discontinued operations in 2017.

United States segment income increased \$756 million after-tax in 2018 compared to 2017 primarily due to higher price realizations and an increase in net sales volumes, which resulted in increased revenues. This increase in revenue was partially offset by an increase in our net loss on commodity derivatives. Additionally, our increase in net sales

volumes resulted in a corresponding increase to production expenses, DD&A, taxes other than income, and shipping, handling and other operating expenses which partially offset the increase to revenues.

International segment income increased \$99 million after-tax in 2018 compared to 2017 as a result of increased income in Other International and the U.K. primarily as a result of increased price realizations and an increase in Other International sales

volumes. Lower expenses in 2018 were primarily driven by lower DD&A expense as a result of the decrease in estimated U.K. asset retirement costs, lower E.G. sales volumes and the sale of certain Other International properties. This was partially offset by lower income in Libya due to the 2018 sale of our Libya subsidiary (see [Note 5](#) to the consolidated financial statements for further information).

Consolidated Results of Operations: 2017 compared to 2016

Revenues from contracts with customers are presented by segment in the table below:

(In millions)	Year Ended	
	2017	2016
Revenues from contracts with customers		
United States	\$3,093	\$2,331
International	1,154	665
Segment revenues from contracts with customers	\$4,247	\$2,996

Below is a price/volume analysis for each segment. Refer to the preceding [Operations](#) and [Market Conditions](#) sections for additional detail related to our net sales volumes and average price realizations.

(In millions)	Year Ended December 31, 2016	Increase (Decrease) Related to		Year Ended December 31, 2017
		Price Realizations	Net Sales Volumes	
United States Price/Volume Analysis <sup>(a)</sup>				
Crude oil and condensate	\$ 1,852	\$ 525	\$ 25	\$ 2,402
Natural gas liquids	189	117	18	324
Natural gas	274	58	29	361
Other sales	16			6
Total	\$ 2,331			\$ 3,093
International Price/Volume Analysis				
Crude oil and condensate	\$ 537	\$ 214	\$ 249	\$ 1,000
Natural gas liquids	9	5	1	15
Natural gas	87	4	6	97
Other sales	32			42
Total	\$ 665			\$ 1,154

<sup>(a)</sup> Year ended December 31, 2016 includes sales volumes of 14 mboed on an annualized basis relating to assets sold when compared to 2017, primarily consisting of the disposition of Wyoming and certain non-operated CO<sub>2</sub> and waterflood assets in West Texas and New Mexico in 2016.

Net gain (loss) on commodity derivatives decreased \$30 million in 2017 from 2016. We have multiple crude oil and natural gas derivative contracts indexed to NYMEX WTI and Henry Hub. We record commodity derivative gains/losses as the index pricing and forward curves change each period. See [Note 14](#) to the consolidated financial statements for further information.

Marketing revenues decreased \$78 million in 2017 from 2016, primarily as a result of lower marketed volumes in the United States segment due to non-core asset dispositions. Marketing activities include the purchase of commodities from third parties for resale and serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points. Since the volume of marketing activity is based on

market dynamics, it can fluctuate from period to period.

Income from equity method investments increased \$81 million primarily due to higher price realizations from LPG at our Alba plant and methanol at our AMPCO methanol facility. Also contributing to the increase was improvement in net sales volumes primarily driven by the completion of the Alba field compression project in E.G. during the second half of 2016.

Net gain on disposal of assets decreased \$331 million in 2017 from 2016. This decrease was primarily related to the sale of non-core assets in the first half of 2016 in Wyoming, West Texas and New Mexico, and the Gulf of Mexico. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions.

Other income increased \$25 million in 2017 from 2016. This increase was primarily a result of a downward revision in U.K. estimated asset retirement costs as well as timing of abandonment activities in the U.K. See Item 8. Financial Statements and Supplementary Data - Note 12 to the consolidated financial statements for detail about our asset retirement obligation.

Production expenses remained nearly flat during 2017 while our sales volumes from continuing operations increased. During 2017, our production expense rate (expense per boe) for United States was lower primarily due to the disposition of higher cost non-core assets in Wyoming. The International expense rate decreased in the year of 2017 primarily due to an increase in sales volumes in E.G. and Libya, combined with lower maintenance costs in E.G.

(\$ per boe)	2017	2016
Production Expense Rate	\$476	\$486
Rate	\$5.57	\$5.96
International	\$239	\$234
Rate	\$4.51	\$5.26

Marketing costs decreased \$77 million in 2017 from the prior year, consistent with the decrease in marketing revenues discussed above.

Shipping, handling, and other operating expenses decreased \$53 million compared to 2016 which included the termination payment of our Gulf of Mexico deepwater drilling commitment in 2016.

Exploration expenses increased \$86 million in 2017 versus the comparable 2016 period, due primarily to charges taken as a result of lower forecasted long-term commodity prices and the anticipated sales of certain non-core properties in our International segment. In 2017, we recorded non-cash charges of \$159 million comprised of \$95 million in unproved property impairments in our International segment and \$64 million dry well costs related to our Diaba License G4-223 in the Republic of Gabon. Additionally, our decision not to develop the Tchicuate offshore Block in the Republic of Gabon resulted in an increase to exploration expenses of \$43 million during 2017. Unproved property impairments during 2016 primarily consist of non-cash charges related to our decision to not drill our remaining Gulf of Mexico leases.

The following table summarizes the components of exploration expenses:

(In millions)	Year Ended December 31, 2017	2016
Exploration Expenses		
Unproved property impairments	\$246	\$195
Dry well costs	77	25
Geological and geophysical	25	5
Other	61	98
Total exploration expenses	\$409	\$323

Exploration expense are also discussed in Item 8. Financial Statements and Supplementary Data - Note 11 to the consolidated financial statements.

Depreciation, depletion and amortization increased \$216 million in 2017 from the prior year primarily as a result of an increase of \$176 million in the United States due to a 5% increase in net sales volumes, and an increase in the DD&A rates within our U.S. resource plays. Also contributing to this higher expense was an increase of \$52 million in our International segment resulting from increased sales volumes due to the completion and start-up of our E.G. Alba field compression project in mid-2016, and the resumption of sales volumes and production in Libya. Our segments apply the units-of-production method to the majority of their assets, including capitalized asset retirement costs; therefore, volumes have an impact on DD&A expense.

The DD&A rate (expense per boe), which is impacted by field-level changes in sales volumes, reserves and capitalized costs, can also cause changes to our DD&A. The DD&A rate for United States increased primarily due to the sales volume mix between our U.S. resource plays, and the outside-operated Gunflint field achieving first production in mid-2016. Also contributing to the increase was a reduction to the Eagle Ford proved developed reserve base in the fourth quarter of 2016. The DD&A rate for our International segment remained relatively consistent with the 2016 rate. The following table provides DD&A rates for each segment.

(\$ per boe)	2017	2016
DD&A Rate		
United States	\$23.51	\$22.49

International \$6.19 \$6.21

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Impairments increased \$162 million in 2017 from the comparable 2016 period. This increase was primarily consisting of \$136 million of proved property impairments in certain non-core properties in our International segment as a result of our anticipated sales and lower forecasted long-term commodity prices. Additionally, included in proved property impairments was \$89 million in 2017 and \$67 million in 2016, both relating to lower forecasted commodity prices in conventional properties in Oklahoma and the Gulf of Mexico. See Item 8. Financial Statements and Supplementary Data - [Note 11](#) to the consolidated financial statement for additional detail.

Taxes other than income includes production, severance and ad valorem taxes, primarily in the U.S., which tend to increase or decrease in relation to revenue and sales volumes. Taxes other than income increased \$32 million in the current year as a result of increased revenue and sales volumes, and due to a reserve being established for non-income tax examinations relating to open tax years.

The following table summarizes the components of taxes other than income:

(In millions)	Year	
	Ended	
	December	
	31,	
	2017	2016
Taxes other than income		
Production and severance	\$ 121	\$ 91
Ad valorem	13	23
Other	49	37
Total taxes other than income	\$ 183	\$ 151

Net interest and other decreased \$62 million during 2017 primarily as a result of the termination of our forward starting interest rate swaps, which resulted in a gain of \$46 million. Additionally, during 2017 we reduced total long-term debt by approximately \$1.75 billion which resulted in a reduction to our net interest and other. The components of net interest and other are detailed in Item 8. Financial Statements and Supplementary Data - [Note 16](#) to the consolidated financial statements.

Loss on early extinguishment of debt increased \$51 million in 2017 primarily due to make-whole call provisions of \$46 million paid upon the redemption of \$1.76 billion in senior unsecured notes. See Item 8. Financial Statements and Supplementary Data - [Note 16](#) to the consolidated financial statements for further detail.

Other net periodic benefit costs decreased \$83 million primarily due to reduced pension settlement charges of \$32 million in 2017 compared to \$103 million in 2016.

Provision (benefit) for income taxes reflects an effective tax rate from continuing operations of 83% and 79% for 2017 and 2016. In 2017, our tax expense was primarily a result of our full valuation allowance on our net federal deferred tax assets throughout 2017 and the effects of our foreign operations. See Item 8. Financial Statements and Supplementary Data - [Note 8](#) to the consolidated financial statements for a discussion of the effective income tax rate. Discontinued operations are presented net of tax. See Item 8. Financial Statements and Supplementary Data - [Note 5](#) to the consolidated financial statements for financial information concerning our discontinued operations.

## Segment Results: 2017 compared to 2016

## Segment Income (Loss)

Segment income (loss) represents income (loss) from continuing operations excluding certain items not allocated to operating segments, net of income taxes. A portion of our corporate and operations general and administrative support costs are not allocated to the operating segments. Gains or losses on dispositions, certain impairments, unrealized gains or losses on commodity derivative instruments, pension settlement losses, or other items (as determined by the CODM) are not allocated to operating segments.

The following table reconciles segment income (loss) to net income (loss):

(In millions)	Year Ended	
	December 31,	
	2017	2016
United States	\$(148 )	\$(415 )
International	374	228
Segment income (loss)	226	(187 )
Items not allocated to segments, net of income taxes <sup>(a)</sup>	(1,056 )	(1,900 )
Income (loss) from continuing operations	(830 )	(2,087 )
Income (loss) from discontinued operations <sup>(b)</sup>	(4,893 )	(53 )
Net income (loss)	\$(5,723 )	\$(2,140 )

<sup>(a)</sup> See Item 8. Financial Statements and Supplementary Data - Note 7 to the consolidated financial statements for further detail about items not allocated to segments.

<sup>(b)</sup> We sold our Canadian business in the second quarter of 2017. The Canadian business is reflected as discontinued operations in all periods presented.

United States segment loss decreased \$267 million in 2017 compared to 2016 primarily due to higher price realizations and higher sales volumes. Partially offsetting this revenue increase was an increase in DD&A and a decrease in the income tax benefit, as we did not realize a tax benefit on any net federal deferred tax assets generated in 2017 due to the full valuation allowance on net federal deferred tax assets in the prior year.

International segment income increased \$146 million in 2017 compared to 2016 primarily due to higher price realizations, and an increase in sales volumes in E.G. and Libya. This was partially offset by an increase in DD&A and income tax expense as a result of the increase in sales volumes.

## Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

Commodity prices are the most significant factor impacting our operating cash flows and the amount of capital available to reinvest into the business. In 2018, we experienced an increase in operating cash flows primarily due to improvements in the commodity price environment with increased consolidated average crude oil and condensate price realizations of over 25% to \$63.32, and an increase to net sales volumes of 11% to 420 mboed.

During 2018 we continued our cash flow growth with highlights that include:

- Cash and cash equivalents increased approximately \$900 million to \$1.5 billion at December 31, 2018.

- Cash provided by operating activities from continuing operations increased by 63%, compared to the same period last year, to \$3,234 million.

- Used this additional cash provided by operating activities to return capital to shareholders by executing \$700 million of share repurchases.

- Received \$750 million in remaining proceeds from the sale of our Canadian business and \$450 million in proceeds from the sale of our Libya subsidiary.

- Additionally these divestiture proceeds were used to capture additional acreage in our resource play leasing and exploration program of \$369 million.

At December 31, 2018, we had approximately \$4.9 billion of liquidity consisting of \$1.5 billion in cash and cash equivalents and \$3.4 billion available under our revolving credit facility. Additionally, during 2018 we extended the maturity date of our Credit Facility from May 28, 2021, to May 28, 2022. As previously discussed in our Outlook section, we are targeting a \$2.6 billion Capital Budget for 2019. We believe our current liquidity level, cash flow from operations and ability to access the capital markets provides us with the flexibility to fund our business throughout the different commodity price cycles. We will continue to evaluate the commodity price environment and our spending



throughout 2019.

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## Cash Flows

The following table presents sources and uses of cash and cash equivalents from continuing operations for 2018, 2017 and 2016:

(In millions)	Year Ended December 31,		
	2018	2017	2016
Sources of cash and cash equivalents			
Operating activities - continuing operations	\$3,234	\$1,988	\$901
Disposal of assets, net of cash transferred to the buyer	1,264	1,787	1,219
Common stock issuance	—	—	1,236
Borrowings	—	988	—
Other	93	68	56
Total sources of cash and cash equivalents	\$4,591	\$4,831	\$3,412
Uses of cash and cash equivalents			
Additions to property, plant and equipment	\$(2,753)	\$(1,974)	\$(1,204)
Additions to other assets	(26 )	(25 )	—
Acquisitions, net of cash acquired	(25 )	(1,891 )	(902 )
Purchases of common stock	(713 )	(11 )	(6 )
Debt repayments	—	(2,764 )	(1 )
Debt extinguishment costs	—	(46 )	—
Dividends paid	(169 )	(170 )	(162 )
Other	(6 )	(5 )	(6 )
Total uses of cash and cash equivalents	\$(3,692)	\$(6,886)	\$(2,281)

Cash flows generated from operating activities in 2018 were 63% higher as both commodity price realizations and net sales volumes improved compared to 2017. Consolidated average crude oil and condensate price realizations increased by over 25% and net sales volumes increased 11% during 2018 as compared to 2017.

Proceeds from the disposals of assets for 2018 are primarily related to our non-operated interest in Libya as well as the remaining proceeds from the sale of our Canadian business. Proceeds from the disposals of assets for 2017 is primarily the result of the disposal of our Canadian business, and in 2016 are primarily from the sale of our Wyoming upstream and midstream assets, as well as the sale of certain other non-operated CO<sub>2</sub> and waterflood assets in West Texas and New Mexico. Disposition transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements.

Issuance of common stock reflects net proceeds received in 2016 from our public sale of common stock.

Borrowings in 2017 are a result of the issuance of \$1 billion of 4.4% senior unsecured notes due in 2027. Financing transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – Note 16 to the consolidated financial statements for additional information.

Additions to property, plant and equipment reflect a significant use of cash and cash equivalents. The following table shows capital expenditures related to continuing operations by segment and reconciles to additions to property, plant and equipment as presented in the consolidated statements of cash flows:

(In millions)	Year Ended December 31,		
	2018	2017	2016
United States <sup>(a)</sup>	\$2,620	\$2,081	\$936
International	39	42	82
Corporate	26	27	18
Total capital expenditures	2,685	2,150	1,036
Change in capital expenditure accrual	68	(176 )	168
Total use of cash and cash equivalents for property, plant and equipment	\$2,753	\$1,974	\$1,204

<sup>(a)</sup> 2018 capital expenditures includes 1,800 net acres in New Mexico for \$105 million acquired from the Bureau of Land Management lease sale.



Additions to other assets relates to deposits on our resource play leasing and exploration program. During 2018 our resource play leasing and exploration capital expenditures totaled \$369 million, largely including costs within property, plant and equipment, other assets and acquisitions. These expenditures were more than fully funded through the divestiture proceeds received in 2018.

During 2017, we closed on multiple Permian basin acquisitions for approximately \$1.9 billion with cash on hand. Additionally, during 2016, we closed the Oklahoma STACK acquisition for a purchase price of \$904 million, net of cash acquired. See Item 8. Financial Statements and Supplementary Data – Note 4 to the consolidated financial statements for further information concerning acquisitions.

In 2018, we acquired 36 million common shares at a cost of \$700 million, excluding transaction fees and commissions, under our share repurchase program. Shares purchased were held as treasury stock. See Note 23 to the consolidated financial statements for additional information.

In December 2017, we redeemed \$1 billion of 5.125% municipal revenue bonds due in 2037 in a refunding transaction. Additionally, during the third quarter of 2017, we used the net proceeds of the borrowing disclosed above plus existing cash on hand to redeem \$1.76 billion in senior unsecured notes resulting in a recognized loss on early extinguishment of debt of \$46 million, primarily due to make-whole call provisions. Financing transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – Note 16 to the consolidated financial statements for additional information.

During 2018, 2017 and 2016, the Board of Directors approved a \$0.05 per share quarterly dividend. See Capital Requirements below for additional information about the fourth quarter 2018 dividend.

#### Liquidity and Capital Resources

In October 2018, we extended the maturity date of our Credit Facility from May 28, 2021, to May 28, 2022. Fees on the unused commitment to the lenders, as well as the borrowing options under the Credit Facility, remain unaffected by the term extension. We retain the ability to request two one-year extensions and an option to increase the commitment amount by up to an additional \$107 million, subject to the consent of any increasing lenders. The sub-facilities for swing-line loans and letters of credit remain unchanged allowing up to an aggregate amount of \$100 million and \$500 million, respectively.

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, sales of non-core assets, capital market transactions, and our revolving Credit Facility. At December 31, 2018, we had approximately \$4.9 billion of liquidity consisting of \$1.5 billion in cash and cash equivalents and \$3.4 billion available under our revolving Credit Facility. Our working capital requirements are supported by these sources and we may draw on our revolving Credit Facility to meet short-term cash requirements, or issue debt or equity securities through the shelf registration statement discussed below as part of our longer-term liquidity and capital management program. Because of the alternatives available to us as discussed above, we believe that our short-term and long-term liquidity are adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending budgets, dividend payments, defined benefit plan contributions, repayment of debt maturities, and other amounts that may ultimately be paid in connection with contingencies.

General economic conditions, commodity prices, and financial, business and other factors could affect our operations and our ability to access the capital markets. Our corporate credit ratings as of December 31, 2018 are: Standard & Poor's Ratings Services BBB- (positive); Fitch Ratings BBB (stable); and Moody's Investor Services, Inc. Ba1 (positive). A downgrade in our credit ratings could increase our future cost of financing or limit our ability to access capital, and result in additional collateral requirements. See Item 1A. Risk Factors for a discussion of how a further downgrade in our credit ratings could affect us.

Additionally, in December of 2017, we redeemed \$1 billion of 5.125% municipal revenue bonds due in 2037 in a refunding transaction that preserved our ability to remarket up to \$1 billion of tax-exempt municipal bonds prior to 2037. We may incur additional debt in order to fund our capital expenditures, acquisitions or development activities, or for general corporate or other purposes. A higher level of indebtedness could increase the risk that our liquidity and financial flexibility deteriorates. See Item 1A. Risk Factors for a further discussion of how our level of indebtedness could affect us.

#### Capital Resources

#### Credit Arrangements and Borrowings

At December 31, 2018, we had no borrowings against our revolving credit facility.

At December 31, 2018, we had \$5.5 billion in long-term debt outstanding, with our next debt maturity in the amount of \$600 million due in 2020. We do not have any triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit ratings.

### Shelf Registration

We have a universal shelf registration statement filed with the SEC under which we, as a "well-known seasoned issuer" for purposes of SEC rules, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

### Asset Disposals

We entered into an agreement to sell our subsidiary, Marathon Oil KDV B.V., which holds our 15% non-operated interest in the Atrush block in Kurdistan for proceeds of \$63 million, before closing adjustments. Disposition transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements.

### Debt-To-Capital Ratio

The Credit Facility includes a covenant requiring that our ratio of total debt to total capitalization not exceed 65% as of the last day of each fiscal quarter. Our debt-to-capital ratio was 31% at December 31, 2018 and 32% at December 31, 2017.

(In millions)	2018	2017
Long-term debt due within one year	\$—	\$—
Long-term debt	5,499	5,494
Total debt	\$5,499	\$5,494
Equity	\$12,128	\$11,708
Calculation		
Total debt	\$5,499	\$5,494
Total debt plus equity (total capitalization)	\$17,627	\$17,202
Debt-to-capital ratio	31	% 32 %

### Capital Requirements

#### Capital Spending

Our approved Capital Budget for 2019 is \$2.6 billion. Additional details were previously discussed in Outlook.

#### Share Repurchase Program

In 2018, we acquired 36 million common shares at a cost of \$700 million under our share repurchase program. The remaining share repurchase authorization as of December 31, 2018 is \$800 million.

#### Other Expected Cash Outflows

On January 30, 2019, our Board of Directors approved a dividend of \$0.05 per share for the fourth quarter of 2018. The dividend is payable on March 11, 2019 to shareholders of record on February 20, 2019.

We plan to make contributions of up to \$50 million to our funded pension plans during 2019. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately \$5 million and \$18 million in 2019.

### Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2018.

(In millions)	Total	2019	2020- 2021	2022- 2023	Later Years
Short and long-term debt (includes interest) <sup>(a)</sup>	\$8,521	\$256	\$1,087	\$1,680	\$5,498
Lease obligations	217	62	89	17	49
Purchase obligations:					
Oil and gas activities <sup>(b)</sup>	69	58	1	1	9
Service and materials contracts <sup>(c)</sup>	122	83	39	—	—
Transportation and related contracts	1,355	327	330	229	469
Other <sup>(d)</sup>	39	18	21	—	—
Total purchase obligations	1,585	486	391	230	478
Other long-term liabilities reported in the consolidated balance sheet <sup>(e)</sup>	548	149	65	56	278
Total contractual cash obligations <sup>(f)</sup>	\$10,871	\$953	\$1,632	\$1,983	\$6,303

<sup>(a)</sup> Includes anticipated cash payments for interest of \$256 million for 2019, \$487 million for 2020-2021, \$443 million for 2022-2023 and \$1,798 million for the remaining years for a total of \$2,984 million.

Oil and gas activities include contracts to acquire property, plant and equipment and commitments for oil and gas

<sup>(b)</sup> exploration such as costs related to contractually obligated exploratory work programs that are expensed immediately.

<sup>(c)</sup> Service and materials contracts include contracts to purchase services such as utilities, supplies and various other maintenance and operating services.

<sup>(d)</sup> Includes any drilling rigs and fracturing crews that are not considered lease obligations.

Primarily includes obligations for pension and other postretirement benefits including medical and life insurance.

<sup>(e)</sup> We have estimated projected funding requirements through 2027. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs

<sup>(f)</sup> of oil and gas properties of \$1,145 million. See Item 8. Financial Statements and Supplementary Data – Note 12 to the consolidated financial statements.

### Transactions with Related Parties

We own a 63% working interest in the Alba field offshore E.G. Onshore E.G., we own a 52% interest in an LPG processing plant, a 60% interest in an LNG production facility and a 45% interest in a methanol production plant, each through equity method investees. We sell our natural gas from the Alba field to these equity method investees as the feedstock for their production processes.

### Off-Balance Sheet Arrangements

Off-balance sheet arrangements comprise those arrangements that may potentially impact our liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under accounting principles generally accepted in the U.S. Although off-balance sheet arrangements serve a variety of our business purposes, we are not dependent on these arrangements to maintain our liquidity and capital resources, and we are not aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on liquidity and capital resources.

We will issue stand-alone letters of credit when required by a business partner. Such letters of credit outstanding at December 31, 2018, 2017 and 2016 aggregated \$52 million, \$89 million and \$166 million. Most of the letters of credit are in support of obligations recorded in the consolidated balance sheet. For example, they are issued to counterparties to support firm transportation agreements and future abandonment liabilities.

In 2018, we signed an agreement with a lessor to construct and lease a new build-to-suit office building in Houston, Texas. The new Houston office location is expected to be completed in 2021. The lessor and other participants are providing financing for up to \$380 million, to fund the estimated project costs. As of December 31, 2018 project costs incurred totaled \$45 million, primarily for land acquisition costs. The five-year lease term will commence once

construction is substantially complete and the new Houston office is able to be occupied. At the end of the initial lease term, we can extend the term of the lease for an additional five years, subject to the approval of the participants; purchase the property subject to certain terms and conditions; remarket the property to an unrelated third party. As of December 31, 2018 we have recorded this agreement as an operating lease, see Item 8. Financial Statements and Supplementary Data – Note 24 to the consolidated financial statements for further information on operating leases.



### Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies

We have incurred and may continue to incur substantial capital, operating and maintenance and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas and production processes.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We strive to comply with all legal requirements regarding the environment, but as not all costs are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

For more information on environmental regulations that impact us, or could impact us, see Item 1. Business – Environmental, Health and Safety Matters, Item 1A. Risk Factors and Item 3. Legal Proceedings.

#### Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the U.S. requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

#### Estimated Quantities of Net Reserves

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved crude oil and condensate, NGLs and natural gas reserves. The amount of estimated proved reserve volumes affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depreciated, depleted or amortized into net income and the presentation of supplemental information on oil and gas producing activities. In addition, the expected future cash flows to be generated by producing properties are used for testing impairment and the expected future taxable income available to realize deferred tax assets, also in part, rely on estimates of quantities of net reserves. Refer to the applicable sections below for further discussion of these accounting estimates.

The estimation of quantities of net reserves is a highly technical process performed by our engineers and geoscientists for crude oil and condensate, NGLs and natural gas, which is based upon several underlying assumptions. The reserve estimates may change as additional information becomes available and as contractual, operational, economic and political conditions change. We evaluate our reserves using drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. Technologies used in proved reserves estimation includes statistical analysis of production performance, decline curve analysis, pressure and rate transient analysis, pressure gradient analysis, reservoir simulation and volumetric analysis. The observed statistical nature of production performance coupled with highly certain reservoir continuity or quality within the reliable technology areas and sufficient proved developed locations establish the reasonable certainty criteria required for booking proved reserves. The data for a given reservoir may also change over time as a result of numerous factors including, but not limited to, additional development activity, production history and continual reassessment of the viability of production under varying economic conditions.



Reserve estimates are based on an unweighted arithmetic average of commodity prices during the 12-month period, using the closing prices on the first day of each month, as defined by the SEC. The table below provides the 2018 SEC pricing for certain benchmark prices:

	2018 SEC Pricing
WTI Crude oil (per bbl)	\$ 65.56
Henry Hub natural gas (per mmbtu)	\$ 3.05
Brent crude oil (per bbl)	\$ 72.70
Mont Belvieu NGLs (per bbl)	\$ 26.63

When determining the December 31, 2018 proved reserves for each property, the benchmark prices listed above were adjusted using price differentials that account for property-specific quality and location differences.

Estimates of future cash flows associated with proved reserves are based on actual costs of developing and producing proved reserves at the end of the year. If annual SEC crude oil benchmark prices (see table above) were to decrease to approximately \$45 per bbl, or 30% below average prices used to estimate 2018 proved reserves, we would not expect price related reserve revisions to have a material impact on proved reserve volumes. For further discussion of risks associated with our estimation of proved reserves, see Part I. [Item 1A Risk Factors](#).

Depreciation and depletion of crude oil and condensate, NGLs and natural gas producing properties is determined by the units-of-production method and could change with revisions to estimated proved reserves. While revisions of previous reserve estimates have not historically been significant to the depreciation and depletion rates of our segments, any reduction in proved reserves, could result in an acceleration of future DD&A expense. The following table illustrates, on average, the sensitivity of each segment's units-of-production DD&A per boe and pretax income to a hypothetical 10% change in 2018 proved reserves based on 2018 production.

(In millions, except per boe)	Impact of a 10% Increase in Proved Reserves		Impact of a 10% Decrease in Proved Reserves	
	DD&A per boe	Pretax Income	DD&A per boe	Pretax Income
United States	\$(1.85)	\$ 202	\$2.27	\$(246 )
International	\$(0.40)	\$ 18	\$0.49	\$(22 )

#### Asset Retirement Obligations

We have material legal, regulatory and contractual obligations to remove and dismantle long-lived assets and to restore land or seabed at the end of oil and gas production operations. A liability equal to the fair value of such obligations and a corresponding capitalized asset retirement cost are recognized on the balance sheet in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be made. The capitalized asset retirement cost is depreciated using the units-of-production method or the straight line method (dependent on the underlying asset) and the discounted liability is accreted over the period until the obligation is satisfied, the impacts of which are recognized as DD&A in the consolidated statements of income. In many cases, the satisfaction and subsequent discharge of these liabilities is projected to occur many years, or even decades, into the future.

Furthermore, the legal, regulatory and contractual requirements often do not provide specific guidance regarding removal practices and the criteria that must be fulfilled when the removal and/or restoration event actually occurs. Estimates of retirement costs are developed for each property based on numerous factors, such as the scope of the dismantlement, timing of settlement, interpretation of legal, regulatory and contractual requirements, type of production and processing structures, depth of water (if applicable), reservoir characteristics, depth of the reservoir, market demand for equipment, currently available dismantlement and restoration procedures and consultations with construction and engineering professionals. Currency exchange rates, inflation rates and credit-adjusted-risk-free interest rates are then applied to estimate the fair values of the obligations. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted,

with a corresponding adjustment made to the related asset balance or income statement, as appropriate. Changes in estimated asset retirement obligations for late life assets could result in impairment or in the recognition of income. During 2018 we made revisions to these estimates and reduced our recognized liability by \$204 million. This downward revision was primarily due to the acceleration of our U.K. abandonment activities to capture favorable market conditions and lower estimated abandonment costs. See Item 8. Financial Statements and Supplementary Data – Note 12 to the consolidated financial statements for disclosures regarding our asset retirement obligation estimates.

An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of obligations that must be assessed, the number of underlying assumptions and the wide range of possible assumptions.

#### Fair Value Estimates

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value, or range of present values, using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and do not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.

Level 3 – Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. See Item 8. Financial Statements and Supplementary Data – Note 15 to the consolidated financial statements for disclosures regarding our fair value measurements.

Significant uses of fair value measurements include:

- impairment assessments of long-lived assets;
- impairment assessments of goodwill; and
- recorded value of derivative instruments.

The need to test long-lived assets and goodwill for impairment can be based on several indicators, including a significant reduction in prices of crude oil and condensate, NGLs and natural gas, sustained declines in our common stock, reductions to our Capital Budget, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment in which the property is located.

#### Impairment Assessments of Long-Lived Assets

Long-lived assets in use are assessed for impairment whenever changes in facts and circumstances indicate that the carrying value of the assets may not be recoverable. For purposes of an impairment evaluation, long-lived assets must be grouped at the lowest level for which independent cash flows can be identified, which generally is field-by-field or, in certain instances, by logical grouping of assets if there is significant shared infrastructure or contractual terms that cause economic interdependency amongst separate, discrete fields. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition is less than the carrying value of an asset group, the

carrying value is written down to the estimated fair value. During 2018 the anticipated sales of certain non-core proved properties in our International and United States segments triggered an assessment of certain of our long-lived assets related to oil and gas producing properties for impairment. We estimated the fair values using a market approach, based upon anticipated sales proceeds less costs to sell, and recognized impairments. As of December 31, 2018 our estimated undiscounted cash flows relating to our remaining long-lived assets significantly exceeded their carrying values in our core assets. Long-lived assets most at risk for future impairment had

an estimated carrying value of less than \$50 million. See Item 8. Financial Statements and Supplementary Data [Note 11](#) and [Note 15](#) to the consolidated financial statements for discussion of impairments recorded in 2018, 2017 and 2016 and the related fair value measurements.

Fair value calculated for the purpose of testing our long-lived assets for impairment is estimated using the present value of expected future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

Future crude oil and condensate, NGLs and natural gas prices. Our estimates of future prices are based on our analysis of market supply and demand and consideration of market price indicators. Although these commodity prices may experience extreme volatility in any given year, we believe long-term industry prices are driven by global market supply and demand. To estimate supply, we consider numerous factors, including the worldwide resource base, depletion rates and OPEC production policies. We believe demand is largely driven by global economic factors, such as population and income growth, governmental policies and vehicle stocks. The prices we use in our fair value estimates are consistent with those used in our planning and capital investment reviews. There has been significant volatility in crude oil and condensate, NGLs and natural gas prices and estimates of such future prices are inherently imprecise. See Item 1A. Risk Factors for further discussion on commodity prices.

Estimated quantities of crude oil and condensate, NGLs and natural gas. Such quantities are based on a combination of proved reserves and risk-weighted probable reserves and resources such that the combined volumes represent the most likely expectation of recovery. See Item 1A. Risk Factors for further discussion on reserves.

Expected timing of production. Production forecasts are the outcome of engineering studies which estimate reserves, as well as expected capital programs. The actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money. The expected timing of production that we use in our fair value estimates is consistent with that used in our planning and capital investment reviews.

Discount rate commensurate with the risks involved. We apply a discount rate to our expected cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. A higher discount rate decreases the net present value of cash flows.

Future capital requirements. Our estimates of future capital requirements are based upon a combination of authorized spending and internal forecasts.

We base our fair value estimates on projected financial information which we believe to be reasonably likely to occur. An estimate of the sensitivity to changes in assumptions in our undiscounted cash flow calculations is not practicable, given the numerous assumptions (e.g. reserves, pace and timing of development plans, commodity prices, capital expenditures, operating costs, drilling and development costs, inflation and discount rates) that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced commodity prices on future undiscounted cash flows would likely be partially offset by lower costs.

#### Impairment Assessments of Goodwill

Goodwill is tested for impairment on an annual basis, or between annual tests when events or changes in circumstances indicate the fair value may have been reduced below its carrying value. Goodwill is tested for impairment at the reporting unit level. Our reporting units are the same as our reporting segments, of which only International includes goodwill. As of December 31, 2018, our consolidated balance sheet included goodwill of \$97 million. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. We first assess the qualitative factors in order to determine whether the fair value of our International reporting unit is more likely than not less than its carrying amount. Certain qualitative factors used in our evaluation include, among other things, the results of the most recent quantitative assessment of the goodwill impairment test, macroeconomic conditions; industry and market conditions (including commodity prices and cost factors); overall financial performance; and other relevant entity-specific events. If, after considering these events and circumstances we determined that it is more likely than not that the fair value of the International reporting unit is less than its carrying amount, a quantitative goodwill test is performed. The quantitative goodwill test is performed using a combination of market and income approaches. The market approach references observable inputs specific to us and

our industry, such as the price of our common equity, our enterprise value, and valuation multiples of us and our peers from the investor analyst community. The income approach utilizes discounted cash flows, which are based on forecasted assumptions. Key assumptions to the income approach are the same as those described above regarding our impairment assessment of long lived assets and are consistent with those that management uses to make business decisions.



During the second quarter of 2018, we performed our annual impairment test of goodwill using the qualitative assessment. Our qualitative assessment considered the significant excess fair value over carrying value in our most recent step 1 test (second quarter 2017) and noted a general improvement in the qualitative factors above. After assessing the totality of the qualitative factors which could have a positive or negative impact on goodwill, our assessment did not indicate that it is more likely than not that the fair value is less than its carrying value. As a result, we concluded that no impairment to goodwill was required for our International reporting unit. We believe the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in such assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. See Item 8. Financial Statements and Supplementary Data Note 13 to the consolidated financial statements for additional discussion of goodwill.

#### Derivatives

We record all derivative instruments at fair value. Fair value measurements for all our derivative instruments are based on observable market-based inputs that are corroborated by market data and are discussed in Item 8. Financial Statements and Supplementary Data – Note 14 to the consolidated financial statements. Additional information about derivatives and their valuation may be found in Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

#### Income Taxes

We are subject to income taxes in numerous taxing jurisdictions worldwide. Estimates of income taxes to be recorded involve interpretation of complex tax laws and assessment of the effects of foreign taxes on our U.S. federal income taxes.

Uncertainty exists regarding tax positions taken in previously filed tax returns which remain subject to examination, along with positions expected to be taken in future returns. We provide for unrecognized tax benefits, based on the technical merits, when it is more likely than not that an uncertain tax position will not be sustained upon examination. Adjustments are made to the uncertain tax positions when facts and circumstances change, such as the closing of a tax audit; court proceedings; changes in applicable tax laws, including tax case rulings and legislative guidance; or expiration of the applicable statute of limitations.

We have recorded deferred tax assets and liabilities, measured at enacted tax rates, for temporary differences between book basis and tax basis, tax credit carryforwards and operating loss carryforwards. In accordance with U.S. GAAP accounting standards, we routinely assess the realizability of our deferred tax assets and reduce such assets, to the expected realizable amount, by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. In assessing the need for additional or adjustments to existing valuation allowances, we consider all available positive and negative evidence. Positive evidence includes reversals of temporary differences, forecasts of future taxable income, assessment of future business assumptions and applicable tax planning strategies that are prudent and feasible. Negative evidence includes losses in recent years as well as the forecasts of future income (loss) in the realizable period. In making our assessment regarding valuation allowances, we weight the evidence based on objectivity.

We base our future taxable income estimates on projected financial information which we believe to be reasonably likely to occur. Numerous judgments and assumptions are inherent in the estimation of future taxable income, including factors such as future operating conditions and the assessment of the effects of foreign taxes on our U.S. federal income taxes. Future operating conditions can be affected by numerous factors, including (i) future crude oil and condensate, NGLs and natural gas prices, (ii) estimated quantities of crude oil and condensate, NGLs and natural gas, (iii) expected timing of production, and (iv) future capital requirements. These assumptions are described in further detail above regarding our impairment assessment of long-lived assets. An estimate of the sensitivity to changes in assumptions resulting in future taxable income calculations is not practicable, given the numerous assumptions that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced commodity prices on future taxable income would likely be partially offset by lower capital expenditures.

Based on the assumptions and judgments described above, as of December 31, 2018, we reflect a valuation allowance in our consolidated balance sheet of \$749 million against our gross deferred tax assets of \$2.0 billion in various jurisdictions in which we operate. Our gross deferred tax assets consist primarily of federal U.S. operating loss carryforwards of \$655 million, which will expire in 2035 - 2037, and \$472 million in 2018 which can be carried

forward indefinitely. Since December 31, 2016, we have maintained a full valuation allowance on our net federal deferred tax assets. If objective negative evidence in the form of cumulative losses are no longer present and additional weight is given to subjective evidence such as forecasted projections of taxable income in future years, we would adjust the amount of the federal deferred tax assets considered realizable and reduce the provision for income taxes in the period of adjustment. See Item 8. Financial Statements and Supplementary Data – Note 8 to the consolidated financial statements for further detail.

### Pension and Other Postretirement Benefit Obligations

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the following:

- the discount rate for measuring the present value of future plan obligations;
- the expected long-term return on plan assets;
- the rate of future increases in compensation levels; and

We develop our demographics and utilize the work of third-party actuaries to assist in the measurement of these obligations. We have selected different discount rates for our U.S. pension plans and our other U.S. postretirement benefit plans due to the different projected benefit payment patterns. In determining the assumed discount rates, our methods include a review of market yields on high-quality corporate debt and use of our third-party actuary's discount rate model. This model calculates an equivalent single discount rate for the projected benefit plan cash flows using a yield curve derived from bond yields. The yield curve represents a series of annualized individual spot discount rates from 0.5 to 99 years. The bonds used are rated AA or higher by a recognized rating agency, only non-callable bonds are included and outlier bonds (bonds that have a yield to maturity that significantly deviates from the average yield within each maturity grouping) are removed. Each issue is required to have at least \$300 million par value outstanding. The constructed yield curve is based on those bonds representing the 50% highest yielding issuances within each defined maturity group.

Of the assumptions used to measure obligations and estimated annual net periodic benefit cost as of December 31, 2018 the discount rate has the most significant effect on the periodic benefit cost reported for the plans. The hypothetical impacts of a 0.25% change in the discount rates of 4.26% for our U.S. pension plans and 4.09% for our other U.S. postretirement benefit plans is summarized in the table below:

(In millions)	Impact of a 0.25% Increase in Discount Rate		Impact of a 0.25% Decrease in Discount Rate	
	Obligation	Expense	Obligation	Expense
U.S. pension plans	\$ (3 )	\$ —	\$ 3	\$ —
Other U.S. postretirement benefit plans	\$ (1 )	\$ —	\$ 1	\$ —

The asset rate of return assumption for the funded U.S. plan considers the plan's asset mix (currently targeted at approximately 55% equity and 45% other fixed income securities), past performance and other factors. Certain components of the asset mix are modeled with various assumptions regarding inflation, debt returns and stock yields. Decreasing the 6.50% asset rate of return assumption by 0.25% would not have a significant impact on our defined benefit pension expense.

Compensation change assumptions are based on historical experience, anticipated future management actions and demographics of the benefit plans. Health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends.

Item 8. Financial Statements and Supplementary Data – Note 18 to the consolidated financial statements includes detailed information about the assumptions used to calculate the components of our annual defined benefit pension and other postretirement plan expense, as well as the obligations and accumulated other comprehensive income reported on the consolidated balance sheets.

### Contingent Liabilities

We accrue contingent liabilities for environmental remediation, tax deficiencies related to operating taxes, as well as tax disputes and litigation claims when such contingencies are probable and estimable. Actual costs can differ from estimates for many reasons. For instance, settlement costs for claims and litigation can vary from estimates based on differing interpretations of laws, opinions on responsibility and assessments of the amount of damages. Similarly, liabilities for environmental remediation may vary from estimates because of changes in laws, regulations and their interpretation, additional information on the extent and nature of site contamination and improvements in technology. Our in-house legal counsel regularly assesses these contingent liabilities. In certain circumstances outside legal counsel is utilized.

We generally record losses related to these types of contingencies as other operating expense or general and administrative expense in the consolidated statements of income, except for tax contingencies unrelated to income taxes, which are recorded as taxes other than income. For additional information on contingent liabilities, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss.

Accounting Standards Not Yet Adopted

See Item 8. Financial Statements and Supplementary Data – Note 2 to the consolidated financial statements.

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#### Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks related to the volatility of crude oil and condensate, NGLs, and natural gas prices as the volatility of these prices continues to impact our industry. We expect commodity prices to remain volatile and unpredictable in the future, we are also exposed to market risks related to changes in interest rates. We employ various strategies, including the use of financial derivative instruments, to manage the risks related to commodity price fluctuations. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price changes related to the underlying commodity or financial transaction. While the use of derivative instruments could materially affect our results of operations in particular quarterly or annual periods, we believe that the use of these instruments will not have a material adverse effect on our financial position or liquidity. See Item 8. Financial Statements and Supplementary Data – Note 14 and Note 15 to the consolidated financial statements for more information about the fair value measurement of our derivatives, the amounts recorded in our consolidated balance sheets and statements of income and the related notional amounts.

##### Commodity Price Risk

Our strategy is to obtain competitive prices for our products and allow operating results to reflect market price movements dictated by supply and demand. However, management will periodically protect prices on forecasted sales to support cash flow and liquidity, as deemed appropriate. We may use a variety of commodity derivative instruments, including futures, forwards, swaps and combinations of options, as part of an overall program to manage commodity price risk in our business. Our consolidated results for 2018, 2017 and 2016 were impacted by crude oil and natural gas derivatives related to a portion of our forecasted United States sales.

As of December 31, 2018, we had various open commodity derivatives related to crude oil and natural gas with a net asset position of \$127 million. Based on the December 31, 2018, published NYMEX WTI and Henry Hub futures prices, a hypothetical 10% change (per bbl for crude oil and per MMBtu for natural gas) increases (decreases) the fair values of our net commodity derivative open positions as follows:

(In millions)	HypotheticalHypothetical	
	Price	Price
	Increase of 10%	Decrease of 10%
Crude oil derivatives	\$ (30 )	\$ 19
Natural gas derivatives	(1 )	1
Total	\$ (31 )	\$ 20

##### Interest Rate Risk

At December 31, 2018, our portfolio of long-term debt is comprised of fixed-rate instruments with an outstanding balance of \$5.5 billion. Our sensitivity to interest rate movements and corresponding changes in the fair value of our fixed-rate debt portfolio affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices different than carrying value.

##### Counterparty Risk

We are also exposed to financial risk in the event of nonperformance by counterparties. If commodity prices fall below current levels, some of our counterparties may experience liquidity problems and may not be able to meet their financial obligations to us. We review the creditworthiness of counterparties and use master netting agreements when appropriate.

Item 8. Financial Statements and Supplementary Data  
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### Management's Responsibilities for Financial Statements

To the Stockholders of Marathon Oil Corporation:

The accompanying consolidated financial statements of Marathon Oil Corporation and its consolidated subsidiaries ("Marathon Oil") are the responsibility of management and have been prepared in conformity with accounting principles generally accepted in the United States. They necessarily include some amounts that are based on best judgments and estimates. The financial information displayed in other sections of this Annual Report on Form 10-K is consistent with these consolidated financial statements.

Marathon Oil seeks to assure the objectivity and integrity of its financial records by careful selection of its managers, by organization arrangements that provide an appropriate division of responsibility and by communications programs aimed at assuring that its policies and methods are understood throughout the organization.

The Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit and Finance Committee. This Committee, composed solely of independent directors, regularly meets (jointly and separately) with the independent registered public accounting firm, management and internal auditors to monitor the proper discharge by each of their responsibilities relative to internal accounting controls and the consolidated financial statements.

/s/ Lee M. Tillman

/s/ Dane E. Whitehead

Chairman, President and Chief Executive Officer

Executive Vice President and Chief Financial Officer

### Management's Report on Internal Control over Financial Reporting

To the Stockholders of Marathon Oil Corporation:

Marathon Oil's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13(a) – 15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. 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.

An evaluation of the design and effectiveness of our internal control over financial reporting, based on the 2013 framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on the results of this evaluation, Marathon Oil's management concluded that its internal control over financial reporting was effective as of December 31, 2018. The effectiveness of Marathon Oil's internal control over financial reporting as of December 31, 2018 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Lee M. Tillman

/s/ Dane E. Whitehead

Chairman, President and Chief Executive Officer

Executive Vice President and Chief Financial Officer



Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Marathon Oil Corporation:

Opinions on the Financial Statements and Internal Control over Financial Reporting

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

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

Basis for Opinions

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

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

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

#### Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/PricewaterhouseCoopers LLP

Houston, Texas

February 21, 2019

We have served as the Company's auditor since 1982.

MARATHON OIL CORPORATION  
Consolidated Statements of Income

(In millions, except per share data)	Year Ended December 31,		
	2018	2017	2016
Revenues and other income:			
Revenues from contracts with customers	\$5,902	\$4,247	\$2,996
Net gain (loss) on commodity derivatives	(14 )	(36 )	(66 )
Marketing revenues	—	162	240
Income from equity method investments	225	256	175
Net gain (loss) on disposal of assets	319	58	389
Other income	150	78	53
Total revenues and other income	6,582	4,765	3,787
Costs and expenses:			
Production	842	716	720
Marketing, including purchases from related parties	—	168	245
Shipping, handling and other operating	575	431	484
Exploration	289	409	323
Depreciation, depletion and amortization	2,441	2,372	2,156
Impairments	75	229	67
Taxes other than income	299	183	151
General and administrative	394	371	371
Total costs and expenses	4,915	4,879	4,517
Income (loss) from operations	1,667	(114 )	(730 )
Net interest and other	(226 )	(270 )	(332 )
Other net periodic benefit costs	(14 )	(19 )	(102 )
Loss on early extinguishment of debt	—	(51 )	—
Income (loss) from continuing operations before income taxes	1,427	(454 )	(1,164 )
Provision (benefit) for income taxes	331	376	923
Income (loss) from continuing operations	1,096	(830 )	(2,087 )
Income (loss) from discontinued operations	—	(4,893 )	(53 )
Net income (loss)	\$1,096	\$(5,723)	\$(2,140)
Per basic share:			
Income (loss) from continuing operations	\$1.30	\$(0.97 )	\$(2.55 )
Income (loss) from discontinued operations	\$—	\$(5.76 )	\$(0.06 )
Net income (loss)	\$1.30	\$(6.73 )	\$(2.61 )
Per diluted share:			
Income (loss) from continuing operations	\$1.29	\$(0.97 )	\$(2.55 )
Income (loss) from discontinued operations	\$—	\$(5.76 )	\$(0.06 )
Net income (loss)	\$1.29	\$(6.73 )	\$(2.61 )
Weighted average common shares outstanding:			
Basic	846	850	819
Diluted	847	850	819

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

## MARATHON OIL CORPORATION

## Consolidated Statements of Comprehensive Income

(In millions)	Year Ended December 31,		
	2018	2017	2016
Net income (loss)	\$1,096	\$(5,723)	\$(2,140)
Other comprehensive income (loss)			
Postretirement and postemployment plans:			
Change in actuarial loss and other	117	21	16
Income tax provision (benefit)	4	7	(4)
Postretirement and postemployment plans, net of tax	121	28	12
Derivative hedges:			
Net unrecognized gain (loss)	—	(13)	) 61
Reclassification of gains on terminated derivative hedges	—	(47)	) —
Income tax provision (benefit)	—	21	(22)
Derivative hedges, net of tax	—	(39)	) 39
Foreign currency hedges:			
Net recognized loss reclassified to discontinued operations	—	34	—
Income tax provision (benefit)	—	(4)	) —
Foreign currency hedges, net of tax	—	30	—
Other, net of tax	4	2	1
Other comprehensive income (loss)	125	21	52
Comprehensive income (loss)	\$1,221	\$(5,702)	\$(2,088)

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

## MARATHON OIL CORPORATION

## Consolidated Balance Sheets

	December 31,	
	2018	2017
(In millions, except par values and share amounts)		
Assets		
Current assets:		
Cash and cash equivalents	\$1,462	\$563
Receivables, less reserve of \$11 and \$12	1,079	1,082
Notes receivable	—	748
Inventories	96	126
Other current assets	257	36
Current assets held for sale	27	11
Total current assets	2,921	2,566
Equity method investments	745	847
Property, plant and equipment, less accumulated depreciation, depletion and amortization of \$21,830 and \$21,564	16,804	17,665
Goodwill	97	115
Other noncurrent assets	723	764
Noncurrent assets held for sale	31	55
Total assets	\$21,321	\$22,012
Liabilities		
Current liabilities:		
Accounts payable	\$1,320	\$1,395
Payroll and benefits payable	154	108
Accrued taxes	181	177
Other current liabilities	170	288
Current liabilities held for sale	7	—
Total current liabilities	1,832	1,968
Long-term debt	5,499	5,494
Deferred tax liabilities	199	833
Defined benefit postretirement plan obligations	195	362
Asset retirement obligations	1,081	1,428
Deferred credits and other liabilities	279	217
Noncurrent liabilities held for sale	108	2
Total liabilities	9,193	10,304
Commitments and contingencies		
Stockholders' Equity		
Preferred stock - no shares issued or outstanding (no par value, 26 million shares authorized)	—	—
Common stock:		
Issued – 937 million shares and 937 million shares (par value \$1 per share, 1.925 billion shares authorized at December 31, 2018 and 1.1 billion shares authorized at December 31, 2017)	937	937
Held in treasury, at cost – 118 million shares and 87 million shares	(3,816 )	(3,325 )
Additional paid-in capital	7,238	7,379
Retained earnings	7,706	6,779
Accumulated other comprehensive income (loss)	63	(62 )
Total stockholders' equity	12,128	11,708
Total liabilities and stockholders' equity	\$21,321	\$22,012
The accompanying notes are an integral part of these consolidated financial statements.		



MARATHON OIL CORPORATION  
Consolidated Statements of Cash Flows

(In millions)	Year Ended December 31,		
	2018	2017	2016
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income (loss)	\$1,096	\$(5,723)	\$(2,140)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Discontinued operations	—	4,893	53
Depreciation, depletion and amortization	2,441	2,372	2,156
Impairments	75	229	67
Exploratory dry well costs and unproved property impairments	255	323	220
Net (gain) loss on disposal of assets	(319 )	(58 )	(389 )
Deferred income taxes	52	(61 )	828
Net (gain) loss on derivative instruments	14	36	66
Net settlements of derivative instruments	(281 )	45	44
Pension and other post retirement benefits, net	(65 )	(46 )	(3 )
Stock-based compensation	53	49	51
Equity method investments, net	45	20	17
Changes in:			
Current receivables	(133 )	(334 )	67
Inventories	(1 )	10	64
Current accounts payable and accrued liabilities	179	297	(137 )
Other current assets and liabilities	(22 )	1	33
All other operating, net	(155 )	(65 )	(96 )
Net cash provided by operating activities from continuing operations	3,234	1,988	901
Investing activities:			
Additions to property, plant and equipment	(2,753 )	(1,974 )	(1,204 )
Additions to other assets	(26 )	(25 )	—
Acquisitions, net of cash acquired	(25 )	(1,891 )	(902 )
Disposal of assets, net of cash transferred to the buyer	1,264	1,787	1,219
Equity method investments - return of capital	57	64	55
All other investing, net	13	(5 )	(1 )
Net cash used in investing activities from continuing operations	(1,470 )	(2,044 )	(833 )
Financing activities:			
Borrowings	—	988	—
Debt repayments	—	(2,764 )	(1 )
Debt extinguishment costs	—	(46 )	—
Common stock issuance	—	—	1,236
Purchases of common stock	(713 )	(11 )	(6 )
Dividends paid	(169 )	(170 )	(162 )
All other financing, net	23	—	1
Net cash provided by (used in) financing activities	(859 )	(2,003 )	1,068
Net increase in cash and cash equivalents of discontinued operations (Note 5)	—	130	238
Effect of exchange rate on cash and cash equivalents	(2 )	4	(3 )
Cash held for sale	(4 )	—	(2 )
Net increase (decrease) in cash and cash equivalents	899	(1,925 )	1,369
Cash and cash equivalents at beginning of period	563	2,488	1,119
Cash and cash equivalents at end of period	\$1,462	\$563	\$2,488

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





## MARATHON OIL CORPORATION

## Consolidated Statements of Stockholders' Equity

(In millions)	Total Equity of Marathon Oil Stockholders						
	Preferred Stock	Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
December 31, 2015 Balance	\$—	\$ 770	\$(3,554)	\$ 6,498	\$ 14,974	\$ (135 )	\$ 18,553
Shares issued - stock-based compensation	—	—	128	(86 )	—	—	42
Shares repurchased	—	—	(5 )	—	—	—	(5 )
Stock-based compensation	—	—	—	(35 )	—	—	(35 )
Net loss	—	—	—	—	(2,140 )	—	(2,140 )
Other comprehensive income	—	—	—	—	—	52	52
Dividends paid (\$0.20 per share)	—	—	—	—	(162 )	—	(162 )
Common stock issuance	—	167	—	1,069	—	—	1,236
December 31, 2016 Balance	\$—	\$ 937	\$(3,431)	\$ 7,446	\$ 12,672	\$ (83 )	\$ 17,541
Shares issued - stock-based compensation	—	—	117	(50 )	—	—	67
Shares repurchased	—	—	(11 )	—	—	—	(11 )
Stock-based compensation	—	—	—	(17 )	—	—	(17 )
Net loss	—	—	—	—	(5,723 )	—	(5,723 )
Other comprehensive income	—	—	—	—	—	21	21
Dividends paid (\$0.20 per share)	—	—	—	—	(170 )	—	(170 )
Common stock issuance	—	—	—	—	—	—	—
December 31, 2017 Balance	\$—	\$ 937	\$(3,325)	\$ 7,379	\$ 6,779	\$ (62 )	\$ 11,708
Shares issued - stock-based compensation	—	—	221	(109 )	—	—	112
Shares repurchased	—	—	(712 )	—	—	—	(712 )
Stock-based compensation	—	—	—	(32 )	—	—	(32 )
Net income	—	—	—	—	1,096	—	1,096
Other comprehensive income	—	—	—	—	—	125	125
Dividends paid (\$0.20 per share)	—	—	—	—	(169 )	—	(169 )
December 31, 2018 Balance	\$—	\$ 937	\$(3,816)	\$ 7,238	\$ 7,706	\$ 63	\$ 12,128
(Shares in millions)	Preferred Stock	Common Stock	Treasury Stock				
December 31, 2015 Balance	—	770	93				
Shares issued - stock-based compensation	—	—	(3 )				
Common stock issuance	—	167	—				
December 31, 2016 Balance	—	937	90				
Shares issued - stock-based compensation	—	—	(3 )				
December 31, 2017 Balance	—	937	87				

Shares issued - stock-based compensation	—	(6 )
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Shares repurchased	—	37
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December 31, 2018 Balance	—937	118
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The accompanying notes are an integral part of these consolidated financial statements.

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Notes to Consolidated Financial Statements

1. Summary of Principal Accounting Policies

We are an independent exploration and production company engaged in exploration, production and marketing of crude oil and condensate, NGLs and natural gas; as well as production and marketing of products manufactured from natural gas, such as LNG and methanol, in E.G.

Basis of presentation and principles applied in consolidation – These consolidated financial statements, including notes have been prepared in accordance with U.S. GAAP. These consolidated financial statements include the accounts of our controlled subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

During the year, we renamed our United States E&P and International E&P segments to the United States and International segments. The characteristics and composition of these segments remained unchanged and there was no effect on previously reported segment information. See Note 7 for further information on our reportable segments.

Equity method investments – Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting. This includes entities in which we hold majority ownership but the minority stockholders have substantive participating rights in the investee. Income from equity method investments represents our proportionate share of net income generated by the equity method investees and is reflected in revenue and other income in our consolidated statements of income. Equity method investments are included as noncurrent assets on the consolidated balance sheet.

Equity method investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value may have occurred. When a loss is deemed to have occurred and is other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in income. Differences in the basis of the investments and the separate net asset value of the investees, if any, are amortized into income over the remaining useful lives of the underlying assets, except for the excess related to goodwill.

Reclassifications – In the first quarter of 2018 we adopted the new Accounting Standards Codification ("ASC") Topic 606, Revenue from Contracts with Customers using the modified retrospective method. To conform the historical presentation to our current presentation, we reclassified gains/losses arising from our commodity derivatives out of the revenues from contracts with customers line into a separate line, net gain (loss) on commodity derivatives, on the consolidated statements of income. Additionally, in the first quarter of 2018 we adopted the new pension accounting standards update on a retrospective basis, and reclassified the required cost elements from general and administrative expense into production expense, exploration expense, and other net periodic benefit costs. See Note 2 for further discussion of the adoption of these accounting standards.

Additionally, we have reclassified certain prior year amounts between operating cash flow categories to present it on a basis comparable with the current year's presentation with no impact on net cash provided by operating activities.

Discontinued operations – As a result of the sale of our Canadian business in 2017, we reflected this business as discontinued operations in all historical periods presented. Disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations unless otherwise stated. Assets and liabilities are presented as held for sale in the historical periods in the consolidated balance sheets. See Note 5 for discussion of the divestiture in further detail.

Use of estimates – The preparation of financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods.

Estimated quantities of crude oil and condensate, NGLs and natural gas reserves is a significant estimate that requires judgment. All of the reserve data included in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and condensate, NGLs and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and condensate, NGLs and natural gas reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and

geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and condensate, NGLs and natural gas that are ultimately recovered. See Supplementary Data - [Supplementary Information on Oil and Gas Producing Activities](#) for further detail.

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment, asset retirement obligations, goodwill, valuation of derivative instruments and valuation allowances for deferred income tax assets, among others. Although we believe these estimates are reasonable, actual results could differ from these estimates.

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Notes to Consolidated Financial Statements

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Foreign currency transaction gains and losses are included in net income.

Revenue recognition – We recognize revenue at an amount that reflects the consideration to which we believe we are entitled in exchange for transferring goods and/or services to a customer. In the lower 48 states of the U.S., production volumes of crude oil and condensate, NGLs and natural gas are generally sold immediately and transported to market. In international locations, liquid hydrocarbon production volumes may be stored as inventory and sold at a later time. See Note 6 for further discussion of the revenue recognition accounting policies.

Cash and cash equivalents – Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with original maturities of three months or less.

Accounts receivable – The majority of our receivables are from joint interest owners in properties we operate or from purchasers of commodities, both of which are recorded at invoiced amounts and do not bear interest. We often have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We conduct credit reviews of commodity purchasers prior to making commodity sales to new customers or increasing credit for existing customers. Based on these reviews, we may require a standby letter of credit or a financial guarantee. We routinely assess the collectability of receivable balances to determine if the amount of the reserve in allowance for doubtful accounts is sufficient.

Notes receivable – At closing of the sale of our Canadian business in 2017 we received two notes receivable for a combined \$750 million, we received these proceeds in the first quarter of 2018. Both notes receivable were initially recorded at fair value and were reported at amortized cost. These notes receivable were evaluated for collectability on an individual basis each reporting period, based on the financial condition of the debtor. See Note 5 for additional discussion.

Inventories – Crude oil and natural gas are recorded at weighted average cost and carried at the lower of cost or net realizable value. Supplies and other items consist principally of tubular goods and equipment which are valued at weighted average cost and reviewed periodically for obsolescence or impairment when market conditions indicate. We may enter into a contract to sell a particular quantity and quality of crude oil at a specified location and date to a particular counterparty, and simultaneously agree to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. We account for such matching buy/sell arrangements as exchanges of inventory.

Derivative instruments – We may use derivatives to manage a portion of our exposure to commodity price risk, commodity locational risk, foreign currency risk and interest rate risk. All derivative instruments are recorded at fair value. Commodity derivatives and interest rate swaps are reflected on our consolidated balance sheet on a net basis by counterparty, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, foreign currency risk and interest rate risk are classified in operating activities. Our derivative instruments contain no significant contingent credit features.

Fair value hedges – We may use interest rate swaps to manage our exposure to interest rate risk associated with fixed interest rate debt in our portfolio. Changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in net income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

Cash flow hedges – We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings and designate them as cash flow hedges. Derivative instruments designated as cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The effective portion of changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income until the hedged item is reclassified to net income when the underlying forecasted transaction is recognized in net income. Ineffective portions of a cash flow hedge's change in fair value are recognized currently within net interest and other on the consolidated statements of income. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in other comprehensive income is immediately reclassified into net income.

Derivatives not designated as hedges – Derivatives that are not designated as hedges may include commodity derivatives used primarily to manage price and locational risks on the forecasted sale of crude oil and natural gas that we produce. Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income.

Concentrations of credit risk – All of our financial instruments, including derivatives, involve elements of credit and market risk. The most significant portion of our credit risk relates to nonperformance by counterparties. The counterparties to our financial instruments consist primarily of major financial institutions and companies within the energy industry. To manage

MARATHON OIL CORPORATION  
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counterparty risk associated with financial instruments, we select and monitor counterparties based on our assessment of their financial strength and on credit ratings, if available. Additionally, we limit the level of exposure with any single counterparty.

Fair value transfer – We recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. If significant transfers occur, they would be disclosed in Note 15 to the consolidated financial statements.

Property, plant and equipment – We use the successful efforts method of accounting for oil and gas producing activities.

Property acquisition costs – Costs to acquire mineral interests in oil and natural gas properties, to drill exploratory wells in progress and those that find proved reserves, and to drill development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves but cannot yet be classified as proved are capitalized if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended exploratory well costs is monitored continuously and reviewed at least quarterly.

Depreciation, depletion and amortization – Capitalized costs to acquire oil and natural gas properties are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. Support equipment and other property, plant and equipment related to oil and gas producing activities, as well as property, plant and equipment unrelated to oil and gas producing activities, are recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets as summarized below.

Type of Asset	Range of Useful Lives
Office furniture, equipment and computer hardware	4 to 15 years
Pipelines	10 to 40 years
Plants, facilities and infrastructure	3 to 40 years

Impairments – We evaluate our oil and gas producing properties, including capitalized costs of exploratory wells and development costs, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure or contractual terms that cause economic interdependency amongst separate, discrete fields. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is also considered. When unproved property investments are deemed to be impaired, this amount is reported in exploration expenses in our consolidated statements of income.

Dispositions – When property, plant and equipment depreciated on an individual basis is sold or otherwise disposed of, any gains or losses are reflected in net gain (loss) on disposal of assets in our consolidated statements of income.

Gains on the disposal of property, plant and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized either when the assets are classified as held for sale, or are measured using a probability weighted income approach based on both the anticipated sales price and a held-for-use model depending on timing of the sale. Proceeds from the disposal of property, plant and equipment depreciated on a group basis are credited to accumulated depreciation, depletion and amortization with no immediate effect on net income until net book value is reduced to zero.

Goodwill – Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Such goodwill is not amortized, but rather is tested for impairment annually and when

events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to a reporting unit. The fair value of a reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the recorded goodwill is impaired to its implied fair value with a charge to impairments.

Major maintenance activities – Costs for planned major maintenance are expensed in the period incurred and can include the costs of contractor repair services, materials and supplies, equipment rentals and our labor costs.



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Environmental costs – We provide for remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure and are discounted when the estimated amounts are reasonably fixed or reliably determinable. Environmental expenditures are capitalized only if the costs mitigate or prevent future contamination or if the costs improve the environmental safety or efficiency of the existing assets.

Asset retirement obligations – The fair value of asset retirement obligations is recognized in the period in which the obligations are incurred if a reasonable estimate of fair value can be made. Our asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities. Asset retirement obligations for such facilities include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures and restoration costs of land and seabed, including those leased. Estimates of these costs are developed for each property based on the type of production facilities and equipment, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering professionals.

Inflation rates and credit-adjusted-risk-free interest rates are used to estimate the fair value of asset retirement obligations. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis based on estimated proved developed reserves for oil and gas production facilities, while accretion of the liability occurs over the useful lives of the assets.

Deferred income taxes – Deferred tax assets and liabilities, measured at enacted tax rates, are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. We routinely assess the realizability of our deferred tax assets based on several interrelated factors and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. These factors include whether we are in a cumulative loss position in recent years, our reversal of temporary differences, and our expectation to generate sufficient future taxable income. We use the liability method in determining our provision and liabilities for our income taxes, under which current and deferred tax liabilities and assets are recorded in accordance with enacted tax laws and rates.

Stock-based compensation arrangements – The fair value of stock options is estimated on the date of grant using the Black-Scholes option pricing model. The model employs various assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. Of the required assumptions, the expected volatility of our stock price and the stock price in relation to the strike price have the most significant impact on the fair value calculation. We have utilized historical data and analyzed current information which reasonably support these assumptions. The fair value of our restricted stock awards and common stock units is determined based on the market value of our common stock on the date of grant. Unearned stock-based compensation is charged to stockholders' equity when restricted stock awards are granted.

The fair value of our stock-based performance units is estimated using the Monte Carlo simulation method. Since these awards are settled in cash at the end of a defined performance period, they are classified as a liability and are re-measured quarterly until settlement.

Our stock-based compensation expense is recognized based on management's best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods.

## 2. Accounting Standards

### Not Yet Adopted

Lease accounting standard

In February 2016, the FASB issued a new lease accounting standard, which requires lessees to recognize most leases, including operating leases, on the balance sheet as a right of use asset and lease liability. Short-term leases can continue being accounted for off balance sheet based on a policy election. This standard does not apply to leases to explore for or use minerals, oil, natural gas and similar non-regenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained. This standard is effective for us in the first quarter of 2019 and shall be applied using a modified retrospective approach at the beginning of the earliest period presented in the financial statements. Early adoption is permitted.

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In July 2018, the FASB issued a new transition option that allows entities to adopt the new lease accounting standard using the modified retrospective transition method by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption rather than in the earliest period presented. We elected this new transition option and continue to apply the legacy guidance in ASC 840, Leases, including its disclosure requirements, in the comparative periods presented in the year of adoption.

We will adopt the new standard in the first quarter of 2019 and will recognize a right of use asset and lease liability on the adoption date. We will apply practical expedients provided in the standard that allow, among others, not to reassess contracts that commenced or expired prior to the effective date. We also elected a policy not to recognize right of use assets and lease liabilities related to short-term leases.

To facilitate the adoption of this standard, we completed the installation and configuration of a software system in January 2019. While we continue to evaluate our contracts and associated data for compliance with the new standard, we believe the adoption of this standard as of January 1, 2019 will result in the recognition of a right of use asset and related lease liability, on our consolidated balance sheet, between \$160 million to \$210 million.

#### Hedge accounting standard

In August 2017, the FASB issued a new accounting standards update that amends the hedge accounting model to enable entities to hedge certain financial and nonfinancial risk attributes previously not allowed. The amendment also reduces the overall complexity of documenting, assessing and measuring hedge effectiveness. This standard is effective for us in the first quarter of 2019. The amendment mandates modified retrospective adoption when accounting for hedge relationships in effect as of the adoption date. None of our derivative instruments are currently designated as hedges; as a result we do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

#### Goodwill standard

In January 2017, the FASB issued a new accounting standards update that eliminates the requirement to calculate the implied fair value of the goodwill (Step 2 of goodwill impairment test under the current guidance) to measure a goodwill impairment charge. We anticipate the standard to require entities to record an impairment charge based on the excess of a reporting unit's carrying amount over its fair value (measure the charge based on Step 1 under the current guidance). This standard is effective for us in the first quarter of 2020 and shall be applied on a prospective basis. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. We plan to adopt the standard on a prospective basis, and do not expect a material impact on our consolidated results of operations, financial position or cash flows for prior periods.

#### Financial instruments - credit losses

In June 2016, the FASB issued a new accounting standards update that changes the impairment model for trade receivables, net investments in leases, debt securities, loans and certain other instruments. The standard requires the use of a forward-looking "expected loss" model as opposed to the current "incurred loss" model. This standard is effective for us in the first quarter of 2020 and will be adopted on a modified retrospective basis through a cumulative-effect adjustment to retained earnings as of the beginning of the adoption period. Early adoption is permitted starting January 2019. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our consolidated results of operations, financial position or cash flows.

#### Recently Adopted

##### Revenue recognition standard

On January 1, 2018, we adopted the new ASC Topic 606, Revenue from Contracts with Customers and all the related amendments ("new revenue standard") using the modified retrospective method. We evaluated the effect of transition by applying the provisions of the new revenue standard to contracts with remaining obligations as of January 1, 2018. No cumulative adjustment to retained earnings was necessary as a result of adopting this standard.

Results for reporting periods beginning after January 1, 2018 are presented under the new revenue standard, while prior period amounts are not adjusted and continue to be reported in accordance with our historic accounting policies. The primary change relates to the presentation of marketing revenues and marketing expenses from the historical gross presentation to the current net presentation, included within revenues from contracts with customers, for a

portion of our international contracts.

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Notes to Consolidated Financial Statements

We concluded that the adoption of the new revenue standard did not result in any significant changes to our consolidated balance sheet or statement of cash flows. The following tables summarize the impacts of adopting the new revenue standard on our consolidated income statement for the year ended December 31, 2018.

(In millions)	Year Ended December 31, 2018		
	As reported	Adjustments	Presentation without adoption of ASC Topic 606
Revenues and other income:			
Revenues from contracts with customers	\$5,902	\$ (12 )	\$ 5,890
Marketing revenues	—	159	159
Other income	150	(5 )	145
Costs and expenses:			
Marketing, including purchases from related parties	\$—	\$ 158	\$ 158
Shipping, handling and other operating	575	(16 )	559
Pension accounting standard			

In the first quarter of 2018, we adopted the new accounting standards update that changes how employers that sponsor defined pension and/or other postretirement benefit plans present the net periodic benefit cost in the income statement. As a result, employers are required to present the service cost component of net periodic benefit cost in the same income statement line item(s) as other employee compensation costs arising from services rendered during the period. We adopted this standard on a retrospective basis, and reclassified the required cost elements from general and administrative expense into production expense, exploration expense, and other net periodic benefit costs. The adoption of this standard did not have a significant impact on our consolidated balance sheet or statement of cash flows. The following tables summarize the impacts of adopting this standard on our historical consolidated income statement for the years ended December 31, 2017 and 2016.

(In millions)	Year Ended December 31, 2017		
	Previously Reported	As reclassified	Effect of Change Higher/(Lower)
Production	\$706	\$ 716	\$ 10
Exploration	409	409	—
General and administrative	400	371	(29 )
Income (loss) from operations	(133 )	(114 )	19
Other net periodic benefit costs <sup>(a)</sup>	—	(19 )	(19 )

(In millions)	Year Ended December 31, 2016		
	Previously Reported	As reclassified	Effect of Change Higher/(Lower)
Production	\$712	\$ 720	\$ 8
Exploration	323	323	—
General and administrative	481	371	(110 )
Income (loss) from operations	(832 )	(730 )	102
Other net periodic benefit costs <sup>(a)</sup>	—	(102 )	(102 )

<sup>(a)</sup> Includes net settlement loss and other net periodic benefit costs, excluding service costs (See [Note 18](#)).

MARATHON OIL CORPORATION  
Notes to Consolidated Financial Statements

Classification in the statement of cash flows

In August 2016, the FASB issued a new accounting standards update which seeks to reduce the existing diversity in practice in how certain transactions are classified in the statement of cash flows. This standard was effective for us in the first quarter of 2018, and was applied retrospectively. Adoption of this standard did not have a significant impact on our consolidated statements of cash flows.

Presentation of restricted cash in the statement of cash flows

In November 2016, the FASB issued a new accounting standards update that requires entities to show the changes in the total of cash, cash equivalents and restricted cash in the statement of cash flows. As a result, we no longer present transfers between cash and cash equivalents and restricted cash in the statement of cash flows. When cash, cash equivalents, and restricted cash are presented in more than one line item on the balance sheet, the standard requires a reconciliation of the totals in the statement of cash flows to the related captions in the balance sheet. This reconciliation can be presented either on the face of the statement of cash flows or in the notes to the financial statements. This standard was effective for us in the first quarter of 2018, and was applied retrospectively. Adoption of this standard did not have a significant impact on our consolidated statements of cash flows.

Accounting for sale or transfer of nonfinancial assets

In February 2017, the FASB issued a new accounting standards update that clarifies the accounting for the sale or transfer of nonfinancial assets and in substance nonfinancial assets to noncustomers, including partial sales. The standard also clarifies that the derecognition of all businesses (except those related to conveyances of oil and gas mineral rights or contracts with customers) should be accounted for in accordance with the derecognition and deconsolidation guidance in Subtopic 810-10. This standard was effective for us in the first quarter of 2018, and was applied using the modified retrospective approach. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Definition of a business

In January 2017, the FASB issued a new accounting standards update that changes the definition of a business to assist entities with evaluating when a set of transferred assets and activities constitutes a business. The guidance requires us to evaluate if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets; if so, the set of transferred assets and activities would not represent a business. The guidance also requires a business to include at least one substantive process and narrows the definition of outputs by more closely aligning it with how outputs are described in the new revenue guidance. This standard was effective for us in the first quarter of 2018, and was applied prospectively. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Financial instruments updates

In January 2016, the FASB issued an accounting standards update that addresses certain aspects of recognition, measurement, presentation, and disclosure of financial instruments. We adopted this standard in the first quarter of 2018. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

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Notes to Consolidated Financial Statements

3. Income (Loss) and Dividends per Common Share

Basic income (loss) per share is based on the weighted average number of common shares outstanding. Diluted income per share assumes exercise of stock options in all periods, provided the effect is not antidilutive. The per share calculations below exclude 6 million, 11 million and 13 million stock options in 2018, 2017 and 2016 that were antidilutive.

(In millions, except per share data)	Year Ended December 31,		
	2018	2017	2016
Income (loss) from continuing operations	\$1,096	\$(830 )	\$(2,087)
Income (loss) from discontinued operations	—	(4,893 )	(53 )
Net income (loss)	\$1,096	\$(5,723)	\$(2,140)
Weighted average common shares outstanding	846	850	819
Effect of dilutive securities	1	—	—
Weighted average common shares, diluted	847	850	819
Per basic share:			
Income (loss) from continuing operations	\$1.30	\$(0.97 )	\$(2.55 )
Income (loss) from discontinued operations	\$—	\$(5.76 )	\$(0.06 )
Net income (loss)	\$1.30	\$(6.73 )	\$(2.61 )
Per diluted share:			
Income (loss) from continuing operations	\$1.29	\$(0.97 )	\$(2.55 )
Income (loss) from discontinued operations	\$—	\$(5.76 )	\$(0.06 )
Net income (loss)	\$1.29	\$(6.73 )	\$(2.61 )
Dividends per share	\$0.20	\$0.20	\$0.20

4. Acquisitions

2017 - United States Segment

In the fourth quarter of 2017, we closed on our acquisition of additional acreage in the Northern Delaware basin of New Mexico from a private seller for \$63 million in cash, subject to post-closing adjustments. We accounted for this transaction as an asset acquisition, allocating the purchase price to unproved property within property, plant and equipment.

In the second quarter of 2017, we closed on two acquisitions which included approximately 91,000 net acres in the Permian basin of New Mexico. The first acquisition with BC Operating, Inc. and other entities closed for approximately