UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018

or

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File No. 1-8968

Anadarko Petroleum Corporation

(Exact name of registrant as specified in its charter)

Delaware	**76-0146568**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1201 Lake Robbins Drive, The Woodlands, Texas	**77380-1046**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(832) 636-1000**

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

Title of each class	**Name of each exchange on which registered**
Common Stock, par value $0.10 per share	New York Stock Exchange

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

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

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

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

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

The aggregate market value of the Company's common stock held by non-affiliates of the registrant on June 30, 2018, was $37.2 billion based on the closing price as reported on the New York Stock Exchange.

The number of shares outstanding of the Company's common stock at February 1, 2019, is shown below:

Title of Class	**Number of Shares Outstanding**
Common Stock, par value $0.10 per share	499,575,992

Documents Incorporated By Reference

Portions of the Definitive Proxy Statement for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 14, 2019 (to be filed with the Securities and Exchange Commission prior to April 4, 2019), are incorporated by reference into Part III of this Form 10-K.

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COMMONLY USED TERMS AND DEFINITIONS

Unless the context otherwise requires, the terms “Anadarko,” “we”, “our”, and “Company” refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. In addition, the following Company or industry-specific terms and abbreviations are used throughout this report:

364-Day Facility - Anadarko’s $2.0 billion 364-day senior unsecured RCF

3D - Three-dimensional

APC RCF - Anadarko’s $3.0 billion senior unsecured RCF

AROs - Asset retirement obligations

ASR Agreement - An accelerated share-repurchase agreement with an investment bank to repurchase the Company’s common stock

ASU - Accounting Standards Update

Bbl - Barrel

Bcf - Billion cubic feet

BOE - Barrels of oil equivalent

CBM - Coalbed methane

COSF - Centralized oil stabilization facility

DBJV - Delaware Basin JV Gathering LLC

DBJV System - A gathering system and related facilities located in the Delaware basin in Loving, Ward, Winkler, and Reeves Counties in West Texas, part of the West Texas Complex effective January 1, 2018

DBM Complex - The processing plants, gas gathering system, and related facilities and equipment in West Texas that serve production from Reeves, Loving, and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico, part of the West Texas Complex effective January 1, 2018

DD&A - Depreciation, depletion, and amortization

DJ - Denver-Julesberg

DJ Basin Complex - The Platte Valley system, Wattenberg system, and Lancaster plant, which were combined into a single complex in Colorado in the first quarter of 2014 to serve production in the DJ basin

E&P - Exploration and production

EOR - Enhanced oil recovery

EPA - U.S. Environmental Protection Agency

FASB - Financial Accounting Standards Board

FID - Final investment decision

Fitch - Fitch Ratings

FPSO - Floating production, storage, and offloading unit

G&A - General and administrative expenses

GAAP - U.S. Generally Accepted Accounting Principles

GHG - Greenhouse gas

GOM Acquisition - The acquisition of oil and natural-gas assets in the Gulf of Mexico that closed on December 15, 2016

IPO - Initial public offering

IRS - U.S. Internal Revenue Service

LIBOR - London Interbank Offered Rate

LNG - Liquefied natural gas

MBbls/d - Thousand barrels per day

MBOE/d - Thousand barrels of oil equivalent per day

Mcf - Thousand cubic feet

MMBbls - Million barrels

MMBOE - Million barrels of oil equivalent
MMBtu - Million British thermal units
MMBtu/d - Million British thermal units per day
MMcf/d - Million cubic feet per day
Moody's - Moody's Investors Service
MTPA - Million tonnes per annum
N/A - Not applicable
NGL or NGLs - Natural-gas liquids
NYMEX - New York Mercantile Exchange
Oil - Includes crude oil and condensate
OPEC - Organization of the Petroleum Exporting Countries
PUD or PUDs - Proved undeveloped reserves
RCF - Revolving credit facility
ROTF - Regional oil treating facility
S&P - Standard and Poor's
SEC - U.S. Securities and Exchange Commission
Share-Repurchase Program - A program authorizing the repurchase of Anadarko's common stock
Sonatrach - The national oil and gas company of Algeria
Tax Reform Legislation - The U.S. Tax Cuts and Jobs Act signed into law on December 22, 2017
Tcf - Trillion cubic feet
TEN - Tweneboa/Enyenra/Ntomme
TEU or TEUs - Tangible equity units
Tronox - Tronox Incorporated
TSR - Total shareholder return
UOP - Unit-of-production
VIE or VIEs - Variable interest entity
WES - Western Gas Partners, LP, a publicly traded limited partnership, which is a consolidated subsidiary of Anadarko
WES 364-Day Facility - WES's $2.0 billion 364-day senior unsecured credit agreement
WES Merger - A merger, which is expected to close in the first quarter of 2019, whereby a wholly owned subsidiary of WGP will merge with and into WES
WES RCF - WES's $1.5 billion senior unsecured RCF
West Texas Complex - The DBM Complex and DBJV and Haley systems, all of which were combined into a single complex effective January 1, 2018.
WTI - West Texas Intermediate
WGEH - Western Gas Equity Holdings, LLC, the general partner of WGP
WGH - Western Gas Holdings, LLC, the general partner of WES
WGP - Western Gas Equity Partners, LP, a publicly traded limited partnership, which is a consolidated subsidiary of Anadarko
WGP RCF - WGP's $35 million senior secured RCF
Zero Coupons - Anadarko's Zero-Coupon Senior Notes due 2036

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company has made in this Form 10-K, and may from time to time make in other public filings, press releases, and management discussions, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, concerning the Company's operations, economic performance, and financial condition. These forward-looking statements include, among other things, information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by, or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," "would," "will," "potential," "continue," "forecast," "future," "likely," "outlook," or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will be realized. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events, or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the following risks and uncertainties:

- *the Company's assumptions about energy markets*
- *production and sales volume levels*
- *levels of oil, natural-gas, and NGL reserves*
- *operating results*
- *competitive conditions*
- *technology*
- *availability of capital resources, levels of capital expenditures, and other contractual obligations*
- *supply and demand for, the price of, and the commercialization and transporting of oil, natural gas, NGLs, and other products or services*
- *volatility in the commodity-futures market*
- *weather*
- *inflation*
- *availability of goods and services, including unexpected changes in costs*
- *drilling and other operational risks*
- *processing volume, pipeline throughput, and produced water disposal*
- *general economic conditions, nationally, internationally, or in the jurisdictions in which the Company is, or in the future may be, doing business*
- *the Company's inability to timely obtain or maintain permits or other governmental approvals, including those necessary for drilling and/or development projects*
- *legislative or regulatory changes, including changes relating to hydraulic fracturing or other oil and natural-gas operations; retroactive royalty or production tax regimes; deepwater and onshore drilling and permitting regulations; derivatives reform; changes in state, federal, and foreign income taxes; environmental regulation, including regulations related to climate change; environmental risks; and liability under international, provincial, federal, regional, state, tribal, local, and foreign environmental laws and regulations*

– *civil or political unrest or acts of terrorism in a region or country*
– *the creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners, and other parties*
– *volatility in the securities, capital, or credit markets and related risks such as general credit, liquidity, and interest-rate risk*
– *the Company's ability to successfully monetize select assets, repay or refinance its debt, successfully complete its debt-reduction program, and the impact of changes in the Company's credit ratings*
– *the Company's ability to successfully complete its Share-Repurchase Program*
– *the Company's ability to successfully plan, secure additional government and partner approvals, enter into additional long-term sales contracts, make a final investment decision and the timing thereof, finance, build, and operate the necessary infrastructure and LNG park in Mozambique*
– *uncertainties and liabilities associated with acquired and divested properties and businesses*
– *disruptions in international oil and NGL cargo shipping activities*
– *physical, digital, internal, and external security breaches*
– *supply and demand, technological, political, governmental, and commercial conditions associated with long-term development and production projects in domestic and international locations*
– *the outcome of pending and future regulatory, legislative, or other proceedings or investigations, including the investigation by the National Transportation Safety Board related to the Company's operations in Colorado, and continued or additional disruptions in operations that may occur as the Company complies with regulatory orders or other state or local changes in laws or regulations in Colorado*
– *the completion of the simplification transaction between WES and WGP and the corresponding sale of substantially all of the Company's Other Midstream assets to WES*
– *other factors discussed below and elsewhere in this Form 10-K, the Company's subsequent Quarterly Reports on Form 10-Q, and in the Company's other public filings, press releases, and discussions with Company management*

PART I

Items 1 and 2. Business and Properties

GENERAL

Anadarko Petroleum Corporation is among the world's largest independent exploration and production companies, with approximately 1.5 billion BOE of proved reserves at December 31, 2018. Anadarko's mission is to deliver competitive and sustainable return to shareholders by developing, acquiring, and exploring for oil and natural-gas resources vital to the world's health and welfare. Successful execution of Anadarko's mission requires a firm commitment to operating safely and in a socially responsible and environmentally friendly manner. Anadarko's strategic objectives are to explore for, develop and commercialize resources globally; ensure health, safety, and environmental excellence; and focus on financial discipline, flexibility, and value creation, while demonstrating the Company's core values of integrity and trust, servant leadership, people and passion, commercial focus, and open communication in all business activities.

Anadarko's asset portfolio is positioned to deliver long-term value to stakeholders by combining cash-generating conventional oil developments in the Gulf of Mexico, Algeria, and Ghana, with a large inventory of significant and proven high-growth unconventional resources in the U.S. onshore. Anadarko's U.S. onshore assets include the Delaware and DJ basins and an emerging play in the Powder River basin. Anadarko's asset portfolio also includes a world-class natural-gas discovery in Mozambique as well as other worldwide exploration and development opportunities.

Anadarko's Exploration and Production and Midstream business segments are managed separately when making operating and capital allocation decisions due to distinct operational differences. The Company's three reporting segments are as follows:

Exploration and Production—This segment is engaged in the exploration, development, production, and sale of oil, natural gas, and NGLs and in advancing its Mozambique LNG project toward an FID in the first half of 2019.

WES Midstream and Other Midstream—These two segments engage in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGL production as well as gathering and disposal of produced water. The WES Midstream segment consists of assets owned by Western Gas Partners, LP, a publicly traded limited partnership, which is a consolidated subsidiary of Anadarko. The Other Midstream segment consists of the Company's midstream assets not owned by WES. At the end of 2018, Anadarko announced the planned contribution and sale of substantially all of its Other Midstream assets to its consolidated subsidiary WES. The sale is expected to close in the first quarter of 2019, after which the Company will have one midstream segment. See *Midstream Properties and Activities* below.

Available Information The Company's corporate headquarters is located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046, and its telephone number is (832) 636-1000. The Company files or furnishes Annual Reports on Form 10-K; Quarterly Reports on Form 10-Q; Current Reports on Form 8-K; registration statements, or any amendments thereto; and other reports and filings with the SEC. Anadarko provides access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing, on its website located at investors.anadarko.com/sec-filings. The Company will also make available to any stockholder, without charge, printed copies of its Annual Report on Form 10-K as filed with the SEC. For copies of this Form 10-K, or any other filing, please contact Anadarko Petroleum Corporation, Investor Relations, P.O. Box 1330, Houston, Texas 77251-1330; call (855) 820-6605; send an email to investor@anadarko.com; or complete an information request on the Company's website at www.anadarko.com by selecting Investors/Shareholder Resources/Shareholder Services.

The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers, including Anadarko, that file electronically with the SEC.

EXPLORATION AND PRODUCTION PROPERTIES AND ACTIVITIES

The Company's Exploration and Production segment actively manages Anadarko's worldwide oil, natural-gas, and NGL sales of its production, as well as the Company's anticipated LNG sales. In marketing its production, the Company attempts to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. The Company's sales of oil, natural gas, and NGLs are generally made at market prices at the time of sale.

The Company sells its products mainly under indexed market price agreements but also from time to time will enter into fixed-price and cost-escalation-based agreements. The Company also engages in limited trading activities for the purpose of generating profits from exposure to changes in market prices of oil, natural gas, and NGLs. The Company does not engage in market-making practices and limits its marketing activities to oil, natural-gas, NGL, and LNG commodity contracts. The Company's marketing-risk position is typically a net short position (reflecting agreements to sell oil, natural gas, and NGLs in the future for specific prices) that is offset by the Company's natural long position as a producer (reflecting ownership of underlying oil and natural-gas reserves). See *Commodity-Price Risk* under Item 7A of this Form 10-K.

ANADARKO'S EXPLORATION AND PRODUCTION PROPERTIES AND ACTIVITIES

Oil and NGLs Anadarko's oil revenues are derived from production in the United States, Algeria, and Ghana. NGL revenues are derived from production in the United States and Algeria. The Company's U.S. oil and NGL production is generally sold under contracts with prices based on relevant market indices, adjusted for location, quality, and transportation. The Company's Algerian and Ghanaian oil is sold into international markets receiving a Brent-linked price. The Company controls firm transportation and fractionation capacity that ensures access to downstream markets, which enables the Company to maximize the value of its oil and NGL production.

Natural Gas Anadarko's natural-gas revenue is derived from production in the United States and is generally sold under contracts with prices based on relevant market indices, adjusted for location and transportation. The Company controls firm-transportation capacity that ensures access to downstream markets, which enables the Company to maximize the value of its natural-gas production. From time to time, the Company stores natural gas in contracted storage facilities to minimize operational disruptions to its ongoing operations and to take advantage of seasonal price differentials. Normally, the Company will have forward contracts in place (physical delivery or financial derivative instruments) against stored natural gas.

United States

Anadarko's U.S. operations include oil and natural-gas exploration and production in the U.S. onshore and deepwater Gulf of Mexico.

2018 U.S. OPERATIONS

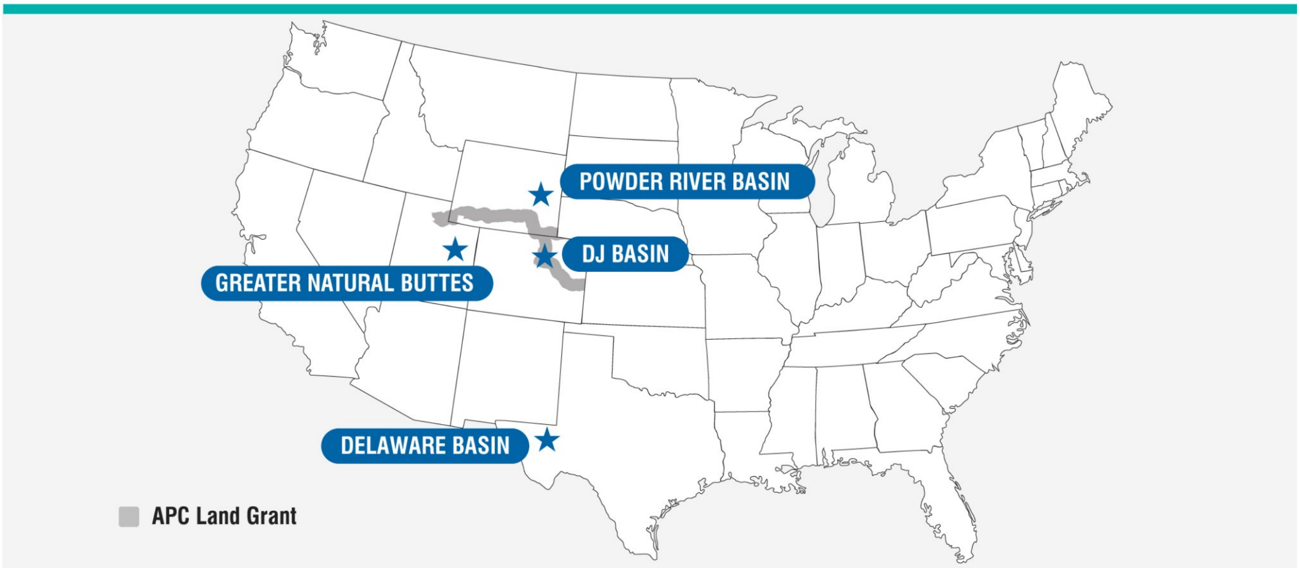
79% OF E&P SALES REVENUES

86% OF SALES VOLUME

90% OF PROVED RESERVES

U.S. Onshore Anadarko's U.S. onshore properties include significant oil and natural-gas plays located in Texas, Colorado, Wyoming, and Utah.

U.S. ONSHORE OIL AND NATURAL-GAS EXPLORATION AND PRODUCTION OPERATIONS



~8,900 OPERATED WELLS

~2,600 NONOPERATED WELLS

466 OPERATED WELLS TURNED TO SALES IN 2018

195 NONOPERATED WELLS TURNED TO SALES IN 2018

Activities in the U.S. onshore during 2018 primarily focused on optimizing wellbore and completion design, improving cost structure, delivering efficient production, and maximizing margin per barrel. The Company also focused on building out infrastructure within its premier positions in the Delaware and DJ basins, while enhancing its acreage position in the Powder River basin. Throughout 2018, the Company continued its efforts to explore for U.S. onshore opportunities that compete within Anadarko's portfolio. In addition, during 2018 the Company divested its nonoperated interests in Alaska. In 2019, the Company expects to continue its horizontal drilling programs in the Delaware and DJ basins, while commencing appraisal activity within the Powder River basin.

The Company also has fee ownership of mineral rights, known as the Land Grant, under 7.3 million acres that pass through Colorado and Wyoming and into Utah. Management considers the Land Grant a significant competitive advantage for Anadarko as it enhances the Company's economic returns from production, offers drilling opportunities for the Company without expiration, and allows the Company to earn royalty revenue from third-party activity on Land Grant acreage.

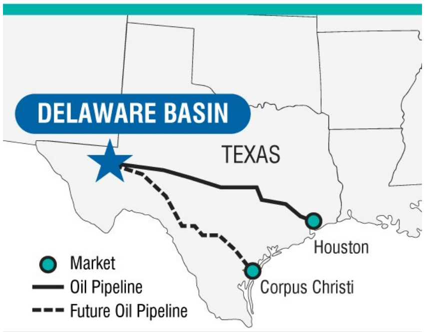
DELAWARE BASIN

Location: West Texas

Acres: 590,000 gross (240,000 net)

Focus Areas:

Wolfcamp and Bone Spring



2018 ACTIVITY

186	109	$1.4 B
OPERATED WELLS TURNED TO SALES	NONOPERATED WELLS TURNED TO SALES	UPSTREAM CAPITAL INVESTMENT

Delaware Basin Anadarko operates approximately 750 wells and owns interests in approximately 450 nonoperated wells in the Delaware basin. The Company's 2018 drilling activity primarily targeted the Wolfcamp shale play, while also testing the liquids-rich Bone Spring tight sands. Having secured operatorship on a majority of its legacy joint venture acreage, the Company continued to build out one of the most expansive and integrated infrastructure positions in the region, primarily in Reeves and Loving counties. In 2018, the Company focused on securing sufficient oil takeaway capacity, ending the year with approximately 46% of its Delaware basin operated oil volume being sold at Gulf Coast markets via the Enterprise pipeline. This capacity is expected to increase to 100% when the Cactus II pipeline is in full service. Anadarko ended 2018 with eight operated drilling rigs and five completion crews.

The successful Wolfcamp shale delineation program continues to deliver encouraging results across the majority of Anadarko's acreage position. Anadarko is testing multiple zones within the Wolfcamp shale and several development concepts for increased efficiency. Included in these development concepts are multi-well pads, extended laterals, enhanced completion designs, and optimized horizontal-well spacing. The Company expects the Wolfcamp shale play to provide substantial opportunity for Anadarko's future activity in the basin.

The Reeves and Loving ROTFs and the first train at the Mentone natural-gas processing plant were placed into service in 2018, adding 120 MBbls/d and 200 MMcf/d of nameplate oil and gas processing capacity to the area. See *Midstream Properties and Activities* for additional discussion on the significant infrastructure added during 2018 to facilitate growth from this asset.

DJ BASIN

Location: Colorado
Acres: 645,000 gross (460,000 net)
Focus Areas:
Niobrara and Codell

2018 ACTIVITY

278 OPERATED WELLS TURNED TO SALES

$1.2 B UPSTREAM CAPITAL INVESTMENT

DJ Basin Anadarko operates approximately 3,400 vertical wells and 1,700 horizontal wells in the Niobrara and Codell formations in the DJ basin. Horizontal drilling results in the field continue to be strong, with enhanced economics realized through the Company's ownership of the Land Grant and operational efficiencies in drilling and completions.

Anadarko continues to drive drilling efficiencies in its DJ basin operations. In 2018, the Company increased its horizontal lateral length by approximately 16% and improved its footage drilled per rig-day by approximately 30% from 2017. The Company ended 2018 with four operated drilling rigs and two completion crews.

The sixth COSF train was placed in service during the third quarter of 2018, adding 30 MBbls/d of oil-stabilization capacity. Construction activities have commenced at the Latham plant, which will deliver 400 MMcf/d of increased natural-gas processing capacity. See *Midstream Properties and Activities* for additional discussion.

POWDER RIVER BASIN

Location: Wyoming
Acres: 676,000 gross (445,000 net)
Focus Area:
Turner

2018 ACTIVITY

2 OPERATED WELLS TURNED TO SALES

Powder River Basin In the southern Powder River basin, Anadarko's acreage is mainly located in Converse County, Wyoming. The field contains the Turner, Niobrara, and Mowry formations that hold both liquids and natural gas. In 2018, the Company invested $181 million on lease acquisitions, accumulating a 300,000 gross-acre position in the southern Powder River basin area, with significant stacked-oil potential.

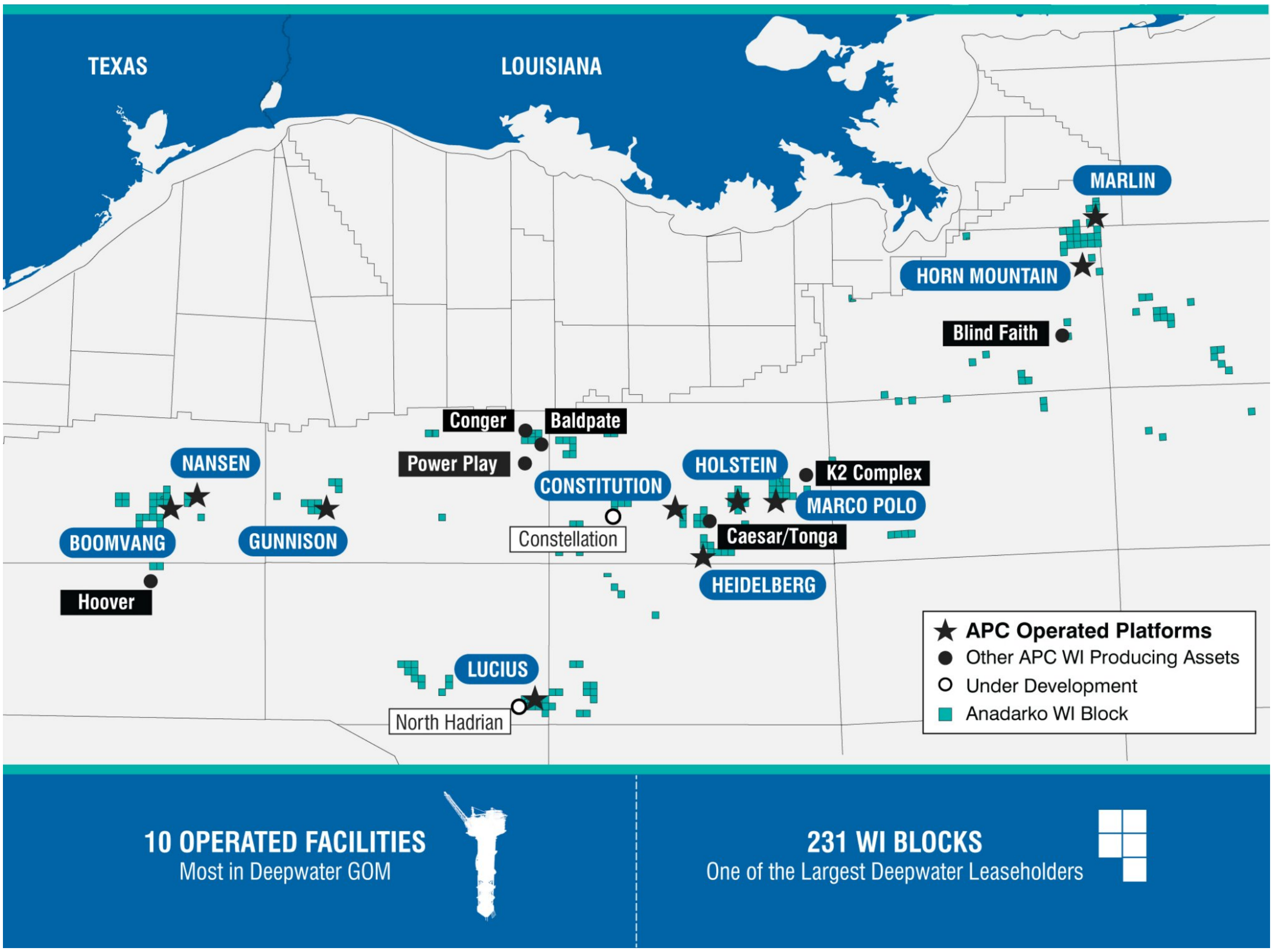
GREATER NATURAL BUTTES
Location: Eastern Utah

2,850
OPERATED WELLS

Greater Natural Buttes The Greater Natural Buttes area in eastern Utah is a tight-gas asset. The Company uses cryogenic and refrigeration processing facilities in this area to extract NGLs from the natural-gas stream. There was minimal activity in this field during 2018 due to capital being allocated to higher-margin projects.

Gulf of Mexico Anadarko owns a working interest in 231 blocks in the Gulf of Mexico, operates 10 active floating platforms, and holds interests in 34 fields. The Company continued an active deepwater development and exploration program in the Gulf of Mexico during 2018, and continues to take advantage of existing infrastructure to cost-effectively develop known resources. The Company plans to operate up to two floating drillships and two platform rigs in 2019.

GULF OF MEXICO OIL AND NATURAL-GAS EXPLORATION AND PRODUCTION OPERATIONS



Development

Horn Mountain (100% working interest)

At Horn Mountain, the Company is successfully executing on its tie-back strategy as oil production continues to exceed expectations. The third development well was drilled in the fourth quarter of 2017 and encountered 42 feet of high-quality oil pay with favorable structural position and good connectivity to existing wells. This well was completed in the first quarter of 2018 and came online in the second quarter of 2018. A platform rig program is currently underway at the spar. The lower platform-rig day rate provides capital-efficient opportunities to increase oil rates in the field. Horn Mountain continues to outperform expectations with total facility gross oil production up by more than 400% since its acquisition in late 2016.

Marlin (100% working interest)

At Marlin, the first tie-back development well was drilled and completed in the King field in the fourth quarter of 2017. The well was brought online in the first quarter of 2018. The Company drilled a second tie-back development well in the Dorado field in the first quarter of 2018. The well encountered 35 feet of high-quality Miocene oil pay and was completed and brought online in the third quarter of 2018. Marlin continues to produce at or near its highest oil rates since the facility was acquired in late 2016.

Additionally, the Company leveraged its infrastructure position to generate revenue with production-handling and cost-sharing agreements on third-party volume. The Crown and Anchor field, which is owned and operated by third parties, was successfully tied back to Marlin and began producing in the second quarter of 2018.

Holstein (100% working interest)

At Holstein, the Company certified the permanently installed platform drilling rig and initiated a four-well drilling program in the fourth quarter of 2017. The first two wells came online in the third quarter of 2018, and the third development well was drilled during the fourth quarter of 2018. Results for the third well were in line with expectations and first production is expected in the first quarter of 2019. Based on the success of this program, the Company plans to drill additional wells in 2019.

Caesar Tonga (33.75% working interest)

At Caesar/Tonga, the Company completed its eighth development well in the second quarter of 2018. The well was tied back to Anadarko's Constitution Spar and came online in the third quarter of 2018. This field continues to produce at or near record-high oil production rates.

Constellation (33.33% working interest)

At Constellation, the Company successfully drilled and completed the first development well in the second quarter of 2017. The well was tied back to Anadarko's Constitution spar and first production was achieved in early 2019.

Lucius (48.9% working interest)

At Lucius, the Company successfully drilled the ninth development well in the third quarter of 2018 and encountered 230 net feet of oil pay in two Pliocene sands. The well was completed and brought online in the fourth quarter of 2018. Spud-to-first-production cycle time was 71 days, a Company record for a deepwater subsea well.

The Company entered into an agreement with partners to expand the Lucius unit to encompass the adjacent Hadrian North discovery in late 2017. The first Hadrian North expansion well concluded drilling in the third quarter of 2018. The well encountered 200 net feet of oil pay in two Pliocene sands and was completed in the fourth quarter of 2018. A second well, originally drilled by the previous operator, was also completed in the fourth quarter of 2018. First production from the North Hadrian two-well expansion is expected by mid-2019.

K2 Complex (41.8% working interest)

At the K2 Complex, the Company successfully drilled and completed the twelfth development well in the second quarter of 2018. The well encountered 220 net feet of oil pay in three Miocene sands and was brought online in the second quarter of 2018 as a tie-back to the Marco Polo facility.

Exploration and Appraisal

The Company continues to create value through successful working interest farmdowns of existing acreage, while also increasing its position through lease sale participation for additional acreage. The Music City and the Sugar exploration wells were drilled in the first quarter of 2018 and were unsuccessful.

International

Anadarko's international operations include oil, natural-gas, and NGL production and development in Algeria and Ghana, along with activities in Mozambique, where the Company continues to make progress toward an FID on an LNG development. The Company also has exploration acreage in Canada, Colombia, Peru, South Africa, and other countries. In 2019, the Company expects to focus its international drilling activity in Ghana and position itself to make a final investment decision on the future LNG development in Mozambique.

2018 INTERNATIONAL OPERATIONS

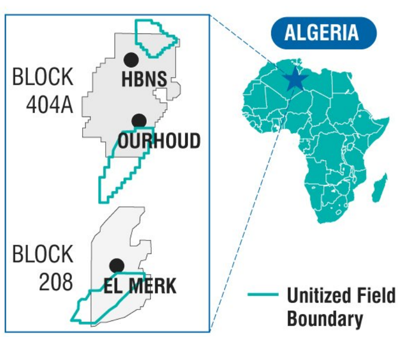
21% OF E&P SALES REVENUES

14% OF SALES VOLUME

10% OF PROVED RESERVES

ALGERIA

Central Processing Facilities:
HBNS, Ourhoud and El Merk



2018 ACTIVITY

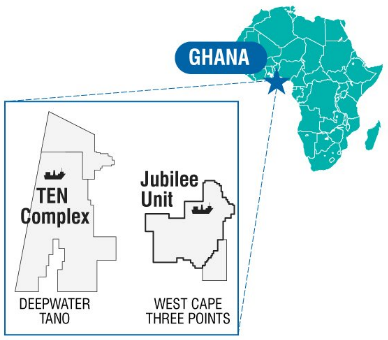
320 MBOE/d TOTAL GROSS PRODUCTION

7 DEVELOPMENT WELLS DRILLED

Algeria Anadarko is engaged in production and development operations in Algeria's Sahara Desert in Blocks 404A and 208, which are governed by a Production Sharing Agreement (PSA) between Anadarko, Sonatrach, and other partners. Under this PSA, the Company is responsible for 24.5% of the development and production costs. The Company produces oil and NGLs through the El Merk central processing facility (CPF) in Block 208 and oil through the Hassi Berkine South and Ourhoud CPFs in Block 404A. Gross production through these facilities averaged more than 320 MBbls/d in 2018, inclusive of 29 days of planned downtime for statutory maintenance at the Hassi Berkine South CPF. The Company drilled seven development wells in 2018 and plans to continue drilling operations throughout 2019.

GHANA

FPSO Vessels:
TEN and Jubilee



2018 ACTIVITY

143 MBbls/d TOTAL GROSS PRODUCTION	**5** DEVELOPMENT WELLS DRILLED

Ghana Anadarko's production and development activities in Ghana are located offshore in the West Cape Three Points Block and the Deepwater Tano Block.

The Jubilee field (27% nonoperated participating interest), which spans both the West Cape Three Points Block and the Deepwater Tano Block, utilizes a 120 MBbls/d-capacity FPSO to produce from subsea wells. Gross production averaged 78 MBbls/d of oil in 2018. An average of 75 MMcf/d of natural gas was exported to an onshore natural-gas processing plant in satisfaction of a commitment established in conjunction with the Jubilee development plan. The partnership received Ghanaian government approval for the full-field plan of development in October 2017 and drilling operations commenced in 2018. The operator drilled, completed, and brought online a production well in each of the third and fourth quarters of 2018. Additionally, a previously drilled water injector well was completed and put into service at the end of 2018.

In 2016, the operator of the Jubilee field announced that damage to the FPSO turret bearing had occurred. As a result, new production and offtake procedures were implemented, and the partners agreed to a long-term solution to convert the FPSO to a permanently spread-moored facility. Interim spread mooring of the FPSO commenced in the fourth quarter of 2016 and was completed in 2017. In 2018, the operator completed the necessary work, including two shutdown periods, to effectively stabilize the turret and rotate the FPSO to its permanent heading. Completion of the permanent spread-mooring anchoring system is expected in early 2019, with no further shutdowns anticipated.

The TEN project (19% nonoperated participating interest), located in the Deepwater Tano Block, utilizes an 80 MBbls/d-capacity FPSO to produce from subsea wells. The project achieved first oil in the third quarter of 2016. However additional field development was delayed due to a border dispute between Ghana and Côte d'Ivoire. In September 2017, the International Tribunal for the Law of the Sea issued a ruling regarding the delimitation of the maritime boundary between Ghana and Côte d'Ivoire in the Atlantic Ocean. The new maritime boundary, as determined by the tribunal, did not affect the TEN fields, and the operator resumed development drilling in the first quarter of 2018. The first well was completed and brought online in the third quarter of 2018. Drilling on two additional wells was completed in the fourth quarter of 2018, with completion activities ongoing at year end. The project averaged gross production of 65 MBbls/d of oil in 2018.

In 2019, the operator plans to drill and complete seven new wells to optimize the deliverability from the Jubilee and TEN fields.

MOZAMBIQUE

Acres: ~1,200,000 gross

GOLFINHO/ATUM ANTICIPATED GROSS	
CAPACITY	PRODUCTION
2 INITIAL TRAINS	~20 SUBSEA WELLS
12.88 MTPA	~2 Bcf/d

Mozambique Anadarko operates Offshore Area 1 (26.5% working interest).

Development In February 2018, the Government of Mozambique approved the Development Plan for the Anadarko-operated, initial two-train Golfinho/Atum onshore LNG project, marking a major milestone required for an FID. Major infrastructure projects, including roads, camps, an airstrip, and resettlement, are underway and proceeding as planned, preparing the area for onshore LNG facility construction. In the third quarter of 2018, Offshore Area 4, which is owned and operated by third parties, joined the Anadarko-led resettlement and airstrip projects as a 50% participant. The preferred offshore construction and installation contractor was selected in the fourth quarter of 2018, and the contracts with the onshore and offshore construction, installation, and equipment contractors are being finalized. Subsequent to year end, LNG sales and purchase agreements (SPAs) were executed with Tokyo Gas Co., Ltd; Centrica LNG Company Ltd., a subsidiary of Centrica plc; Shell International Trading Middle East Ltd; and CNOOC Gas and Power Singapore Trading & Marketing Pte. Ltd, increasing the contracted volume to more than 7.5 MTPA, inclusive of previously announced SPAs executed with Tohoku Electric Power Company, Inc. and Électricité de France, S.A. Execution of SPAs representing 2.0 MTPA of additional contracted volume is anticipated prior to FID.

With progress on major contracts and marketing SPAs, the Company formally launched project financing in December 2018 with the aim of securing funding for up to two-thirds of the required construction capital. The Company is working to finalize project finance arrangements with lenders and secure all partner and government-related approvals required to position the Company to make a final investment decision in the first half of 2019.

Appraisal In Offshore Area 1, the Company completed the interpretations of the re-processed 3D seismic data covering the Orca, Tubarao, and Tubarao-Tigre discovery areas, and continues to assess these areas in accordance with the appraisal program submitted to the Government of Mozambique.

Proved Reserves

Estimates of proved reserves volume owned at year end, net of third-party royalty interests, are presented in Bcf at a pressure base of 14.73 pounds per square inch for natural gas and in MMBbls for oil and NGLs. Total volume is presented in MMBOE. For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserves volume. Proved reserves are estimated based on the average beginning-of-month prices during the 12-month period for the respective year. The average prices used to compute proved reserves at December 31, 2018 were $65.56 per Bbl for oil, $3.10 per MMBtu for natural gas, and $37.68 per Bbl for NGLs.

Disclosures by geographic area include the United States and International. For 2018, the International geographic area consisted of proved reserves located in Algeria and Ghana, which by country and in total represented less than 15% of the Company's total proved reserves.

SUMMARY OF PROVED RESERVES

	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBOE)
December 31, 2018				
Developed				
United States	**392**	**2,564**	**192**	**1,011**
International	**123**	**24**	**10**	**137**
Undeveloped				
United States	**137**	**634**	**66**	**309**
International	**15**	**8**	**—**	**16**
Total proved reserves	**667**	**3,230**	**268**	**1,473**
December 31, 2017				
Developed				
United States	361	2,640	176	977
International	136	24	10	150
Undeveloped				
United States	140	553	56	288
International	21	13	1	24
Total proved reserves	**658**	**3,230**	**243**	**1,439**
December 31, 2016				
Developed				
United States	360	3,637	193	1,159
International	147	25	15	166
Undeveloped				
United States	181	762	75	383
International	14	—	—	14
Total proved reserves	**702**	**4,424**	**283**	**1,722**

The Company's proved-reserves product mix was 63% liquids in 2018, 63% in 2017 and 57% in 2016. The Company's year-end 2018 proved reserves product mix was 45% oil, 37% natural gas, and 18% NGLs.

Changes to the Company's proved reserves during 2018 are summarized in the table below:

MMBOE	2018	2017	2016
Proved Reserves			
January 1	1,439	1,722	2,057
Reserves additions and revisions			
Discoveries and extensions	164	114	40
Infill-drilling additions (1)	181	71	69
Drilling-related reserves additions and revisions	345	185	109
Other non-price-related revisions (1)	(61)	59	191
Net organic reserves additions	284	244	300
Acquisition of proved reserves in place	—	3	97
Price-related revisions (1)	29	92	(147)
Total reserves additions and revisions	313	339	250
Sales in place	(37)	(379)	(294)
Production	(242)	(243)	(291)
December 31	1,473	1,439	1,722
Proved Developed Reserves			
January 1	1,127	1,325	1,632
December 31	1,148	1,127	1,325

(1) Combined and reported as revisions of prior estimates in the Company's *Supplemental Information on Oil and Gas Exploration and Production Activities (Supplemental Information)* under Item 8 of this Form 10-K. Reserves related to infill-drilling additions are treated as positive revisions. Price-related revisions reflect the impact of current prices on the reserves balance at the beginning of each year. Other non-price-related revisions reflect the net change of performance and cost updates, updates to development plans, and all other year-end updates.

The Company's estimates of proved developed reserves, PUDs, and total proved reserves at December 31, 2018, 2017, and 2016, and changes in proved reserves during the last three years are presented in the *Supplemental Information* under Item 8 of this Form 10-K. Also presented in the *Supplemental Information* are the Company's estimates of future net cash flows and discounted future net cash flows from proved reserves. See *Critical Accounting Estimates* under Item 7 of this Form 10-K for additional information on the Company's proved reserves.

The Company has not yet filed information with a federal authority or agency with respect to its estimated total proved reserves at December 31, 2018. Annually, Anadarko reports gross proved reserves for U.S.-operated properties to the U.S. Department of Energy. These reported reserves are derived from the same database used to estimate and report proved reserves in this Form 10-K.

Changes in PUDs Changes to PUDs during 2018 are summarized in the table below. The Company's year-end development plans and associated PUDs are consistent with SEC guidelines for PUD development within five years unless specific circumstances warrant a longer development time horizon.

MMBOE	
PUDs at January 1, 2018	**312**
Revisions of prior estimates	**117**
Extensions, discoveries, and other additions	**47**
Conversions to developed	**(144)**
Sales in place	**(7)**
PUDs at December 31, 2018	**325**

Revisions of prior estimates Revisions of prior estimates reflect Anadarko's ongoing evaluation of its asset portfolio. In 2018, PUDs were revised upward by 117 MMBOE.

MMBOE	**December 31, 2018**
Revisions due to changes in year-end prices (price impact to opening balance)	**—**
Other revisions of prior estimates	
Revisions due to performance	**18**
Revisions due to cost updates	**2**
Revisions due to successful infill drilling	**158**
Revisions due to development plan updates	**(61)**
Total other revisions of prior estimates	**117**
Revisions of prior estimates	**117**

Prior estimates were revised upward by a total of 117 MMBOE and were associated with the following:

- **Performance** The Company experienced an overall increase in PUDs of 18 MMBOE due to performance improvements. Upward revisions of 26 MMBOE were driven primarily by performance improvements in the DJ basin. Downward revisions of 8 MMBOE were primarily due to minor performance reductions in various areas in the Gulf of Mexico and Ghana.
- **Infill-drilling activities** The Company added 158 MMBOE of PUDs associated with infill-drilling activities, with 151 MMBOE in the DJ basin, 5 MMBOE in the Lucius area in the Gulf of Mexico, and the remaining in the Ghana TEN field.
- **Development plan updates** The majority of revisions associated with updates to development plans occurred in the DJ basin due to municipal permit delays in certain areas of the field and ongoing optimization of development activity.

Extensions, discoveries, and other additions The extension of proved acreage in 2018 resulted in an increase in PUDs of 47 MMBOE, of which 24 MMBOE was in the Hadrian North expansion area of the Gulf of Mexico and 23 MMBOE was in the Delaware basin.

Conversions to developed In 2018, the Company converted 144 MMBOE of PUDs to developed status, equating to 34% of total year-end 2017 PUDs when adjusted for revisions and sales. Approximately 79% of PUD conversions occurred in U.S. onshore assets, 15% in Gulf of Mexico assets, and the remaining in international assets.

Anadarko spent $1.1 billion to develop PUDs in 2018, of which approximately 71% related to U.S. onshore assets, 25% related to Gulf of Mexico assets, and the remaining related to international assets.

Sales in place In 2018, PUDs decreased by 7 MMBOE due to the Company's divestiture activities.

Development Plans The Company annually reviews all PUDs to ensure an appropriate plan for development exists. Typically, U.S. onshore PUDs are converted to developed reserves within five years of the initial proved reserves booking, but projects associated with deepwater development and international programs may take longer. At December 31, 2018, the Company had no material pre-2014 PUDs that remained undeveloped. However, the Company did have 15 MMBOE of PUDs scheduled to be developed more than five years from their initial date of booking. Approximately 12 MMBOE of these PUDs are associated with recompletion projects in the Gulf of Mexico, where project timing is dependent upon the current producing horizon achieving its economic limit. The remaining are associated with international drilling projects, which are being developed according to government-approved development plans. The Company did not have any U.S. onshore PUDs scheduled for development more than five years from initial booking.

Technologies Used in Proved Reserves Estimation The Company's proved reserves additions are based on estimates generated through the integration of relevant geological, engineering, and production data, and may include the use of reliable technologies that have been demonstrated in the field to yield reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation as defined in the SEC regulations. Data used in these integrated assessments may include information obtained directly from the subsurface through wellbores such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data used may also include subsurface information obtained through indirect measurements such as seismic data. Reservoir parameters from analogous reservoirs may be used to increase the quality of and confidence in the reserves estimates when available and necessary. The method or combination of methods used to estimate the reserves of each reservoir is based on the unique circumstances of each reservoir and the dataset available at the time of the estimate.

Internal Controls over Reserves Estimation Anadarko's estimates of proved reserves and associated future net cash flows were made solely by the Company's engineers and are the responsibility of management. The Company requires that reserves estimates be made by qualified reserves estimators (QREs) as defined by the Society of Petroleum Engineers' standards. The QREs are assigned to specific assets within the Company's regions. The QREs interact with engineering, land, and geoscience personnel to obtain the necessary data for projecting future production, net cash flows, and ultimate recoverable reserves. Management within each region approves the QREs' reserves estimates. All QREs receive ongoing education on the fundamentals of SEC definitions and reserves reporting through the Company's reserves manual and internal training programs administered by the Corporate Reserves Group (CRG).

The CRG ensures confidence in the Company's reserves estimates by maintaining internal policies for estimating and recording reserves in compliance with applicable SEC definitions and guidance. Compliance with the SEC reserves guidelines is the primary responsibility of Anadarko's CRG.

The CRG is managed through the Company's finance department, which is separate from its operating regions, and is responsible for overseeing internal reserves reviews and approving the Company's reserves estimates. The Director of Corporate Reserves manages the CRG and reports to the SVP—Corporate Planning. The SVP—Corporate Planning reports to the Company's Executive Vice President, Finance and Chief Financial Officer, who in turn reports to the Chairman and Chief Executive Officer. The Governance and Risk Committee of the Company's Board meets with management, members of the CRG, and the Company's independent petroleum consultants, Miller and Lents, Ltd. (M&L), to discuss the results of procedures and methods reviews as discussed below as well as other matters and policies related to reserves.

The Company's principal engineer, who is primarily responsible for overseeing the preparation of proved reserves estimates, has over 32 years of experience in the oil and gas industry, including over 18 years as either a reserves estimator or manager. His further professional qualifications include a degree in petroleum engineering, extensive internal and external reserves training, and asset evaluation and management. The principal engineer is a member of the Society of Petroleum Engineers, where he has been a member for over 32 years, and is also a member of the Society of Petroleum Evaluation Engineers. In addition, he is an active participant in industry reserves seminars and professional industry groups.

Third-Party Procedures and Methods Reviews M&L reviewed the procedures and methods used by Anadarko's staff in preparing the Company's estimates of proved reserves and future net cash flows at December 31, 2018. The purpose of these reviews was to determine if the procedures and methods used by Anadarko to estimate its proved reserves are effective and in accordance with the definitions contained in SEC regulations. The procedures and methods reviews by M&L were limited reviews of Anadarko's procedures and methods and do not constitute a complete review, audit, independent estimate, or confirmation of the reasonableness of Anadarko's estimates of proved reserves and future net cash flows.

The reviews covered 11 fields that included major assets in the United States and Africa and encompassed approximately 93% of the Company's estimates of proved reserves and associated future net cash flows at December 31, 2018. In each review, Anadarko's technical staff presented M&L with an overview of the data, methods, and assumptions used in estimating its reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures, and relevant economic criteria.

Management's intent in retaining M&L to review its procedures and methods is to provide objective third-party input on the Company's procedures and methods and to gather industry information applicable to reserves estimation and reporting processes.

Sales Volume, Prices, and Production Costs

The following provides the Company's annual sales volume, average sales prices, and average production costs per BOE for each of the last three years:

	Sales Volume				Average Sales Prices [1]			
	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Barrels of Oil Equivalent (MMBOE)	Oil (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)	Average Production Costs [2] (Per BOE)
2018								
United States								
DJ basin	**36**	**225**	**22**	**95**	**$ 63.17**	**$ 2.44**	**$ 32.80**	**$ 1.90**
Other United States	**71**	**165**	**14**	**113**	**64.44**	**2.76**	**34.52**	**6.43**
Total United States	**107**	**390**	**36**	**208**	**64.01**	**2.57**	**33.46**	**4.35**
International	**33**	**—**	**2**	**35**	**70.38**	**0.66**	**43.25**	**7.09**
Total	**140**	**390**	**38**	**243**	**65.51**	**2.57**	**33.93**	**4.73**
2017								
United States								
DJ basin	31	212	21	88	$ 49.73	$ 2.55	$ 27.46	$ 1.67
Other United States	66	266	13	123	49.57	3.03	32.24	5.22
Total United States	97	478	34	211	49.62	2.82	29.24	3.75
International	32	—	2	34	53.77	—	35.64	5.84
Total	129	478	36	245	50.66	2.82	29.54	4.04
2016								
United States								
DJ basin	33	214	20	89	$ 40.27	$ 2.00	$ 18.26	$ 1.26
Other United States	52	552	24	168	38.29	2.06	20.21	2.97
Total United States	85	766	44	257	39.06	2.04	19.32	2.37
International	31	—	2	33	43.93	—	25.63	6.28
Total	116	766	46	290	40.34	2.04	19.64	2.81

[1] Excludes the impact of commodity derivatives.
[2] Includes oil and gas operating expenses and other taxes and excludes ad valorem and severance taxes. Volume represents produced volume sold during the period.

Additional information on volume, prices, and production costs is contained in *Financial Results* under Item 7 of this Form 10-K.

Delivery Commitments

The Company sells oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. The Company expects to fulfill these delivery commitments with existing proved developed and proved undeveloped reserves, which the Company regularly monitors to ensure sufficient availability to meet its commitments. If production is not sufficient to meet contractual delivery commitments, the Company may purchase commodities in the market to satisfy its delivery commitments. In areas where Anadarko no longer has production due to asset divestitures, the Company has entered into long-term purchase commitments to satisfy its existing delivery commitments.

The following is a summary of the Company's delivery commitments at December 31, 2018:

	Delivery Commitments				
	2019	**2020**	**2021**	**Thereafter**	**Total**
Oil (MMBbls)					
United States	19	9	—	—	28
International	9	—	—	—	9
Natural-Gas (Bcf)					
United States [(1)]	470	264	224	515	1,473
NGLs (MMBbls)					
United States	4	—	—	—	4

(1) Volume committed to various customers through 2033.

Properties and Leases

The following shows the developed lease, undeveloped lease, and fee mineral acres in which Anadarko held interests at December 31, 2018:

	Developed Lease		Undeveloped Lease		Fee Mineral [(1)]		Total	
thousands	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States								
Onshore	2,272	1,445	545	313	9,868	8,154	12,685	9,912
Offshore	315	183	1,017	822	—	—	1,332	1,005
Total United States	2,587	1,628	1,562	1,135	9,868	8,154	14,017	10,917
International	635	138	36,439	30,536	—	—	37,074	30,674
Total	3,222	1,766	38,001	31,671	9,868	8,154	51,091	41,591

(1) The Company's fee mineral acreage is primarily undeveloped.

At December 31, 2018, the Company had approximately 20.2 million net undeveloped lease acres scheduled to expire by December 31, 2019, if the Company does not establish production or take any other action to extend the terms. The net undeveloped lease acres scheduled to expire by December 31, 2019, if not amended, primarily relate to 20.0 million net acres of international exploration acreage in South Africa (16.0 million net acres) and Colombia (4.0 million acres) where proved reserves have not yet been assigned. The Company plans to continue the terms of many of these licenses and concession areas through operational or administrative actions.

Drilling Program

The Company's 2018 drilling program focused on proven and emerging liquids-rich basins in the United States (onshore and deepwater Gulf of Mexico) and various international locations. Exploration activity in 2018 consisted of 47 gross completed wells in the U.S. onshore. Development activity in 2018 consisted of 637 gross completed wells, which included 615 U.S. onshore wells, 10 Gulf of Mexico wells, and 12 international wells.

Drilling Statistics

The following shows the number of net oil and gas wells completed in each of the last three years:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2018							
United States	**17.0**	**2.0**	**19.0**	**393.7**	**5.4**	**399.1**	**418.1**
International	**—**	**—**	**—**	**2.6**	**—**	**2.6**	**2.6**
Total	**17.0**	**2.0**	**19.0**	**396.3**	**5.4**	**401.7**	**420.7**
2017							
United States	6.6	3.6	10.2	359.1	2.4	361.5	371.7
International	—	7.3	7.3	—	—	—	7.3
Total	6.6	10.9	17.5	359.1	2.4	361.5	379.0
2016							
United States	3.7	1.2	4.9	322.1	—	322.1	327.0
International	—	1.8	1.8	2.9	—	2.9	4.7
Total	3.7	3.0	6.7	325.0	—	325.0	331.7

The following shows the number of wells in the process of drilling or in active completion stages and the number of wells suspended or waiting on completion at December 31, 2018:

	Wells in the process of drilling or in active completion		Wells suspended or waiting on completion [(1)]	
	Exploration	Development	Exploration	Development [(2)]
United States				
Gross	3	45	8	489
Net	0.2	35.2	4.6	370.5
International				
Gross	—	1	25	8
Net	—	0.3	7.1	1.8
Total				
Gross	3	46	33	497
Net	0.2	35.5	11.7	372.3

(1) Wells suspended or waiting on completion include exploration and development wells where drilling has occurred, but the wells are awaiting the completion of hydraulic fracturing or other completion activities or the resumption of drilling in the future.

(2) There were 114 MMBOE of PUDs primarily assigned to U.S. onshore development wells suspended or waiting on completion at December 31, 2018. The Company expects to convert 113 MMBOE of these PUDs reserves to developed status within five years of their initial disclosure. The remaining 1 MMBOE is associated with an international well that was spud late in the year and will be converted to developed status in the near future.

Productive Wells

At December 31, 2018, the Company's ownership interest in productive wells was as follows:

	Oil Wells [(1)]	Gas Wells [(1)]
United States		
Gross	3,976	7,852
Net	2,544.3	6,543.4
International		
Gross	215	9
Net	38.9	2.2
Total		
Gross	4,191	7,861
Net	2,583.2	6,545.6

(1) Includes wells containing multiple completions as follows:

Gross	364	2,510
Net	311.3	2,263.4

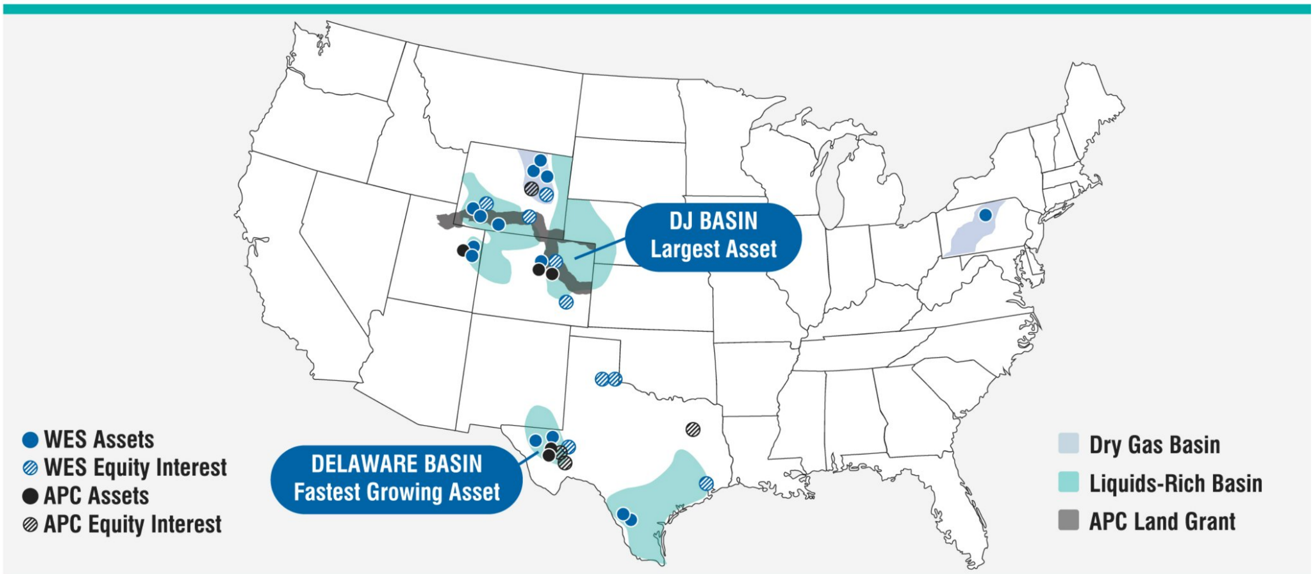
MIDSTREAM PROPERTIES AND ACTIVITIES

Anadarko invests in and operates midstream (gathering, processing, treating, transportation, and produced-water disposal) assets to complement its operations in regions where the Company has oil and natural-gas production. Through ownership and operation of these assets, the Company improves its ability to manage costs, controls the timing of bringing on new production, and enhances the value received for the Company's production. Anadarko also provides midstream services to a variety of third-party customers and generates revenues from its midstream activities through a variety of contract structures, including fixed-fee, percent-of-proceeds, wellhead-purchase, and keep-whole agreements. Anadarko's midstream activities include those of WES, which acquires, owns, develops, and operates midstream assets.

At December 31, 2018, Anadarko's ownership interest in WGP consisted of a 77.8% limited partner interest and the entire non-economic general partner interest. At December 31, 2018, WGP's ownership interest in WES consisted of a 29.6% limited partner interest, the entire 1.5% general partner interest, and all of the WES incentive distribution rights. At December 31, 2018, Anadarko also owned a 9.7% limited partner interest in WES through other subsidiaries.

At the end of 2018, Anadarko announced the planned contribution and sale of substantially all of its midstream assets not owned by WES, which are largely associated with Anadarko's two premier U.S. onshore oil plays in the Delaware and DJ basins, to WES for approximately $4.0 billion, with approximately $2.0 billion of cash proceeds and the balance to be paid in WES common units. Additionally, at the end of 2018, WES announced that a wholly owned subsidiary of WGP will merge with and into WES, with WES continuing as the surviving entity and a subsidiary of WGP, which will result in a simplified midstream structure. Under the terms of the WES Merger, WGP will acquire all of the outstanding publicly held common units of WES and substantially all of the WES common units owned by Anadarko, including the Class C units that will be converted into WES common units immediately prior to the transaction, in a unit-for-unit, tax-free exchange. WES will survive as a partnership with no publicly traded equity, owned 98% by WGP and 2% by Anadarko. WES will remain the borrower for all existing debt, is expected to remain the borrower for all future debt, and will remain the owner of all operating assets and equity investments. Anadarko will maintain operating control of WGP, with approximately 55.5% pro forma ownership of the combined entity. The WES Merger is expected to close in the first quarter of 2019 concurrently with the asset contribution and sale.

ANADARKO'S MIDSTREAM PROPERTIES AND ACTIVITIES



29	71	5	12	~16,500
GATHERING SYSTEMS	PROCESSING & TREATING FACILITIES	NATURAL-GAS PIPELINES	CRUDE OIL/NGL PIPELINES	PIPELINE MILES

WES Midstream

At December 31, 2018, WES Midstream included 19 gathering systems and 46 processing and treating facilities located throughout major onshore producing basins in Wyoming, Colorado, Utah, Pennsylvania, Texas, and New Mexico. In 2018, WES Midstream activity focused on constructing midstream infrastructure in the Delaware basin to prepare for long-term volumetric oil growth, providing additional system expansions in the DJ basin to keep pace with basin activity, and ensuring sufficient access to downstream markets by acquiring options to invest in various transportation assets and long-haul pipelines.

Delaware Basin In 2018, WES expanded its midstream infrastructure for production in the Delaware basin of West Texas, installing approximately 365 miles of gas and water gathering lines. Within its gas gathering system, eight new central gathering facilities (CGFs) were installed and one existing CGF was expanded to add a total of approximately 325 MMcf/d of natural gas compression capacity. One produced-water disposal facility was placed into service during the first quarter of 2018, with capacity of 30,000 barrels of water per day. Additional gas gathering, compression, and produced-water disposal infrastructure is planned for 2019.

With the completion of the Mentone Train I, a 200 MMcf/d cryogenic facility, in the fourth quarter of 2018, the West Texas Complex now includes 1.1 Bcf/d of cryogenic processing capacity, 2,000 gallons per minute of amine-treating capacity, and 28 MBbls/d of high-pressure condensate stabilization capacity. WES expects to add 200 MMcf/d of additional cryogenic processing capacity to the West Texas Complex when the Mentone Train II is completed in the first quarter of 2019.

WES exercised options to acquire a 20% interest in the Midland-to-Sealy crude-oil pipeline, which began full service in April 2018, and a 15% interest in the Cactus II crude-oil pipeline, which is expected to come online in the second half of 2019. Both of these pipelines transport oil from gathering systems in West Texas to market centers along the Gulf Coast. Additionally, WES exercised its option to acquire a 30% interest in the Red Bluff Express pipeline, which was placed into service in May 2018, and closed on the investment in January 2019. This pipeline transport provides crude-oil flow assurance by ensuring residue gas takeaway from natural-gas processing plants in West Texas to the WAHA hub in Pecos County, Texas.

DJ Basin WES continued to optimize its gas gathering system throughout 2018 which resulted in average gathering pipeline pressures believed to be among the lowest in the basin and supportive of stable and consistent production. Management believes that WES is well positioned in the DJ basin with sufficient oil, NGL, and residue gas transportation capacity.

In 2018, WES expanded its midstream infrastructure to support incremental DJ basin production, adding approximately 170 MMcf/d of compression capacity and 35 miles of gas pipeline. In addition, WES completed a bypass at the DJ Basin Complex, which provides for a total of 160 MMcf/d of bypass capacity. In the third quarter of 2018, WES commenced construction of the Latham plant at the DJ Basin Complex, which will consist of two cryogenic gas processing trains that will increase natural-gas processing capacity by 400 MMcf/d. Additional gas gathering and compression system expansions are also planned for 2019.

In 2018, WES participated in the expansion of the Texas/Oklahoma system of the Texas Express Gathering pipeline, which was completed in the second quarter and resulted in total capacity of 100 MBbls/d for the Texas/Oklahoma system. The Texas Express Gathering pipeline ultimately delivers NGLs to the Texas Express Pipeline. In addition, WES elected to participate in the expansion of both the Front Range Pipeline and the Texas Express Pipeline. The expansion of Front Range Pipeline will increase NGL-transport capacity by 100 MBbls/d, and the expansion of Texas Express Pipeline will increase NGL-transport capacity by 90 MBbls/d, with service on the expanded pipelines expected to begin during 2019. These expansions support the ongoing production growth from the DJ basin and provide flow assurance to attractive markets. WES also elected to participate in the conversion of one of the two White Cliffs oil pipelines to a NGL Y-grade pipeline with an initial capacity of 90 MBbls/d. The pipeline will be taken out of service in early 2019 for conversion and is expected to come back online during the fourth quarter of 2019.

Eagleford In the Eagleford shale, WES continues to operate oil and gas gathering systems, with a 2018 average gross throughput of 65 MBbls/d of oil and 440 MMcf/d of natural gas. The 200 MMcf/d operated Brasada natural-gas cryogenic processing plant continued steady operations at capacity.

The following provides information regarding the WES Midstream assets including gathering, processing, treating, transportation, and produced-water disposal by area:

Area	Miles of Pipelines	Total Horsepower (1)	2018 Average Net Throughput (MMcf/d)	2018 Average Net Throughput (MBbls/d)
DJ basin	4,720	302,200	1,110	55
Delaware basin	2,080	412,700	1,040	160
Wyoming	4,210	160,800	840	—
Eagleford	880	202,700	445	40
Greater Natural Buttes	40	74,900	360	10
Other	930	9,700	100	95
Total	12,860	1,163,000	3,895	360

(1) Excludes horsepower associated with transportation assets.

Other Midstream

At the end of 2018, Anadarko's Other Midstream assets included 10 gathering systems and 25 processing and treating facilities located throughout major onshore producing basins in Colorado, Utah, Texas, and New Mexico. In 2018, Anadarko's Other Midstream activity was focused on the build out of its crude-oil gathering and stabilization capacity and produced-water gathering and disposal capacity in the Delaware basin, as well as on expanding its crude-oil gathering and stabilization capacity in the DJ basin.

Delaware Basin In 2018, the Company expanded its midstream infrastructure to further support Anadarko-operated production in the Delaware basin. Oil-stabilization capacity increased by 120 MBbls/d in 2018, as the Reeves ROTF came online in the second quarter and the Loving ROTF came online in the third quarter. Additionally, over 600 miles of oil and water gathering lines were installed, oil pumping stations with a capacity of 125 MBbls/d were completed, and new produced-water disposal facilities added approximately 340,000 barrels of water per day. Additional oil gathering as well as produced-water gathering and disposal expansions are planned for 2019.

DJ Basin In 2018, the sixth stabilizer train at the COSF was placed into service during the third quarter, increasing the facility's nameplate capacity by 30 MBbls/d to 155 MBbls/d of total oil-stabilization capacity.

The following provides information regarding Anadarko's Other Midstream assets including gathering, processing, treating, transportation, and produced-water disposal by area (excluding divestitures closed in 2018):

Area	Miles of Pipelines	Total Horsepower (1)	2018 Average Net Throughput (MMcf/d)	2018 Average Net Throughput (MBbls/d)
DJ basin	1,070	23,300	220	120
Delaware basin	1,140	76,900	150	285
Greater Natural Buttes	1,130	146,800	280	—
Other	300	—	—	15
Total	3,640	247,000	650	420

(1) Excludes horsepower associated with transportation assets.

COMPETITION

The oil and gas business is highly competitive in the exploration for and acquisition of reserves and in the gathering and marketing of oil and gas production. The Company's competitors include national oil companies, major integrated oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies as well as participants in other industries supplying energy and fuel to consumers.

EMPLOYEES

The Company had approximately 4,700 employees at December 31, 2018.

REGULATORY AND ENVIRONMENTAL MATTERS

Environmental and Occupational Health and Safety Regulations

Anadarko's business operations are subject to numerous environmental and occupational health and safety laws and regulations that may be imposed internationally, domestically at the federal, regional, state, tribal and local levels, or by foreign governments. The more significant of these environmental and occupational health and safety laws and regulations include the following legal standards that currently exist in the United States, as amended from time to time:

- the U.S. Clean Air Act, which restricts the emission of air pollutants from many sources and imposes various pre-construction, operational, monitoring, and reporting requirements, and that the EPA has relied upon as authority for adopting climate change regulatory initiatives relating to GHG emissions
- the U.S. Federal Water Pollution Control Act, also known as the federal Clean Water Act, which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States
- the U.S. Oil Pollution Act of 1990, which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to liability for removal costs and damages arising from an oil spill in waters of the United States
- U.S. Department of the Interior (which includes Bureau of Land Management (BLM), Bureau of Indian Affairs (BIA), Bureau of Ocean Energy Management (BOEM) and Bureau of Safety and Environmental Enforcement (BSEE) regulations), which govern operations on federal lands and waters and impose obligations for establishing financial assurances for decommissioning activities, liabilities for pollution cleanup costs resulting from operations, and potential liabilities for pollution damages
- the U.S. Comprehensive Environmental Response, Compensation and Liability Act of 1980, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur
- the U.S. Resource Conservation and Recovery Act, which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes
- the U.S. Safe Drinking Water Act (SDWA), which ensures the quality of the nation's public drinking water through adoption of drinking water standards and control over the injection of waste fluids into below-ground formations that may adversely affect drinking water sources
- the U.S. Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories
- the U.S. Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures
- the U.S. Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas
- the U.S. National Environmental Policy Act, which requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to impact the environment and that may require the preparation of environmental assessments and more detailed environmental impact statements that may be made available for public review and comment
- U.S. Department of Transportation regulations, which relate to advancing the safe transportation of energy and hazardous materials and emergency response preparedness

Additionally, there exist regional, state, tribal and local jurisdictions in the United States where the Company operates that also have, or are developing or considering developing, similar environmental and occupational health and safety laws and regulations governing many of these same types of activities. Outside of the United States, there are foreign countries and provincial, regional, tribal or local jurisdictions therein where the Company is conducting business that also have, or may be developing, regulatory initiatives or analogous controls that regulate Anadarko's environmental-related activities. While the legal requirements imposed in foreign countries or jurisdictions therein may be similar in form to U.S. laws and regulations, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter, delay or cancel the permitting, development, or expansion of a project or substantially increase the cost of doing business. Moreover, both in the United States and in foreign countries, environmental and occupational health and safety laws and regulations, including new or amended legal requirements that may arise in the future to address potential environmental concerns such as air and water impacts or to address perceived health or safety-related concerns such as oil and natural-gas development in close proximity to specific occupied structures and/or certain environmentally-sensitive or recreational areas, are expected to continue to have a considerable impact on the Company's operations.

Anadarko has acquired certain oil and natural-gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons, hazardous substances or wastes were not under Anadarko's control. Under environmental laws and regulations, Anadarko could incur liability for remediating hydrocarbons, hazardous substances or wastes disposed of or released by prior owners or operators. Anadarko also could incur costs related to the clean-up of third-party sites to which it sent regulated substances for disposal or to which it sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at or from such third-party sites.

Furthermore, regulatory bodies at the federal, regional, state, tribal and local levels in the United States as well as internationally, and certain non-governmental organizations have been increasingly focused on GHG emissions and climate change issues. In addition to the EPA's rule applicable to onshore and offshore sources of oil and natural-gas production and requiring annual reporting of GHG emissions, the EPA has adopted regulations for certain large sources regulating GHG emissions as pollutants under the U.S Clean Air Act. In 2016, the EPA published a final rule requiring operators to reduce methane emissions and emissions of volatile organic compounds from new, modified and reconstructed crude oil and natural gas wells and equipment located at natural gas production gathering and booster stations, gas processing plants and natural gas transmission compressor stations. The EPA is reconsidering this rule and has proposed to stay its requirements but this proposed rule has not been finalized and, thus, the 2016 final rule remains in effect, subject to amendments issued by the agency in March 2018. Developments in GHG initiatives may affect us and other similarly situated companies operating in the oil and natural-gas industry.

These environmental and occupational health and safety laws and regulations generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays or cancellations in the permitting, development, or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company's activities in a particular area. Moreover, there exist environmental laws that provide for citizen suits, which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. See *Risk Factors* under Item 1A of this Form 10-K for further discussion on hydraulic fracturing; ozone standards; induced seismicity regulatory developments; climate change, including methane or other GHG emissions; and other regulatory initiatives relating to environmental protection.

The Company has incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with environmental and occupational health and safety laws and regulations. Historically, the Company's environmental compliance costs have not had a material adverse effect on its results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on the Company's business and operation results. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as existing standards are subject to change and new standards continue to evolve. Although the Company is not fully insured against all environmental and occupational health and safety risks, and the Company's insurance does not cover any penalties or fines that may be issued by a governmental authority, it maintains insurance coverage that it believes is sufficient based on the Company's assessment of insurable risks and consistent with insurance coverage held by other similarly situated industry participants. Nevertheless, it is possible that other developments, such as stricter and more comprehensive environmental and occupational health and safety laws and regulations as well as claims for damages to property or persons or imposition of penalties resulting from the Company's operations, could have a material adverse effect on Anadarko and its results of operations.

Oil Spill-Response Plan

Domestically, the Company is subject to compliance with the federal BSEE regulations, which, among other standards, require every owner or operator of a U.S. offshore lease to prepare and submit for approval an oil spill-response plan prior to conducting any offshore operations. The submitted plan is required to provide a detailed description of actions to be taken in the event of a spill; identify contracted spill-response equipment, materials, and trained personnel; and stipulate the time necessary to deploy identified resources in the event of a spill. The BSEE regulations may be amended, resulting in more stringent requirements with respect to the amount and type of spill-response resources to which an owner or operator must maintain ready access. Accordingly, resources available to the Company may change to satisfy any new regulatory requirements or to adapt to changes in the Company's operations.

Anadarko has in place and maintains Oil Spill-Response Plans (Plans) for the Company's Gulf of Mexico operations. The Plans set forth procedures for rapid and effective responses to spill events that may occur as a result of Anadarko's operations.

As part of the Company's oil spill-response preparedness, and as set forth in the Plans, Anadarko maintains membership in Clean Gulf Associates (CGA). CGA was created to provide a means of effectively staging response equipment and to provide effective spill-response capability for its member companies operating in the Gulf of Mexico. Anadarko is also a member of the Marine Preservation Association, which provides full access to the Marine Spill Response Corporation (MSRC) cooperative. In the event of a spill, MSRC stands ready to mobilize all of its equipment and materials. MSRC has a fleet of dedicated Responder Class Oil Spill Response Vessels (OSRVs), designed and built to recover spilled oil. The Company is also a member of the Marine Well Containment Company (MWCC) which provides access to subsea intervention, containment, capture, and shut-in capacity for deepwater exploration wells. MWCC is open to oil and gas operators in the U.S. Gulf of Mexico and provides members access to oil spill-response equipment and services on a per-well fee basis.

Anadarko has emergency and oil spill-response plans in place for each of its exploration and operational activities around the globe. Each plan is intended to satisfy the requirements of relevant local or national authorities, describes the actions the Company is expected to take in the event of an incident, includes drills conducted by the Company at least annually, and includes reference to external resources that may become necessary in the event of an incident. Included in these external resources is the Company's contract with Oil Spill Response Limited (OSRL), a global emergency and oil spill-response organization headquartered in London.

TITLE TO PROPERTIES

As is customary in the oil and gas industry, a preliminary title review is conducted at the time properties believed to be suitable for drilling operations are acquired by the Company. Prior to the commencement of drilling operations, thorough title examinations of the drill site tracts are conducted by third-party attorneys, and curative work is performed with respect to significant defects, if any, before proceeding with operations. Anadarko believes the title to its leasehold properties is good, defensible, and customary with practices in the oil and gas industry, subject to such exceptions that, in the opinion of legal counsel for the Company, do not materially detract from the use of such properties.

Leasehold properties owned by the Company are subject to royalty, overriding royalty, and other outstanding interests customary in the industry. The properties may be subject to burdens such as liens incident to operating agreements, current taxes, development obligations under oil and gas leases and other encumbrances, easements, and restrictions. Anadarko does not believe any of these burdens will materially interfere with its use of these properties.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age at January 31, 2019	Position
R. A. Walker	61	Chairman and Chief Executive Officer
Robert G. Gwin	55	President
Benjamin M. Fink	48	Executive Vice President, Finance and Chief Financial Officer
Daniel E. Brown	43	Executive Vice President, U.S. Onshore Operations
Mitchell W. Ingram	56	Executive Vice President, International, Deepwater and Exploration
Amanda M. McMillian	45	Executive Vice President and General Counsel
Christopher O. Champion	49	Senior Vice President, Chief Accounting Officer and Controller

Mr. Walker was named Chairman of the Board of the Company in May 2013, in addition to the role of Chief Executive Officer and director, both of which he assumed in May 2012. He also served as President from February 2010 until November 2018. He previously served as Chief Operating Officer from March 2009 until his appointment as Chief Executive Officer. He served as Senior Vice President, Finance and Chief Financial Officer from September 2005 until March 2009. From August 2007 until March 2013, he served as director of WGH and served as its Chairman of the Board from August 2007 to September 2009. Mr. Walker served as a director of WGEH from September 2012 until March 2013. Mr. Walker served as a director of CenterPoint Energy, Inc. from April 2010 to April 2015 and has served as a director of BOK Financial Corporation since April 2013, where he is the Chairman of the Risk Committee.

Mr. Gwin was named President in November 2018. Prior to this position, he served as Executive Vice President, Finance and Chief Financial Officer since May 2013; Senior Vice President, Finance and Chief Financial Officer since March 2009; and Senior Vice President since March 2008. He served as Chairman of the Board of WGH from October 2009 until November 2018 and has served as a director since August 2007. Additionally, Mr. Gwin served as Chairman of the Board of WGEH from September 2012 until November 2018 and served as President of WGH from August 2007 to September 2009 and as Chief Executive Officer of WGH from August 2007 to January 2010. He joined Anadarko in January 2006 as Vice President, Finance and Treasurer and served in that capacity until March 2008. He served as Chairman of the Board of LyondellBasell Industries N.V. from August 2013 through September 2018 and as a director from May 2011 through November 2018.

Mr. Fink was named Executive Vice President, Finance and Chief Financial Officer in November 2018. Prior to that, Mr. Fink was named Senior Vice President in February 2017 and previously served as Vice President, Finance and Assistant Treasurer since May 2013, having joined Anadarko in 2007. Mr. Fink also served as President of WGH and WGEH from May 2017 to November 2018 and as Chief Executive Officer of WGH and WGEH from May 2017 to January 2019. In addition, he has served as a director of WGH since February 2017. He previously served as President, Chief Executive Officer, Chief Financial Officer and Treasurer of WGH and WGEH from February 2017 to May 2017, and as Senior Vice President and Chief Financial Officer of WGH from 2009 to February 2017 and of WGEH since its formation in September 2012 to February 2017.

Mr. Brown was named Executive Vice President, U.S. Onshore Operations in October 2017. Prior to this position, he served as Executive Vice President, International and Deepwater Operations since May 2017; Senior Vice President, International and Deepwater Operations since August 2016; Vice President, Operations (Southern and Appalachia) since August 2013; and Vice President, Corporate Planning since May 2013. Mr. Brown joined Anadarko upon the acquisition of Kerr-McGee Corporation in August 2006. He has held positions of increasing responsibility with Anadarko and Kerr-McGee Corporation, where he began his career, including General Manager of the Maverick basin and the Company's Freestone/Chalk area, Business Advisor for Planning and Reserves Administration in the Gulf of Mexico, and in engineering positions in both the U.S. onshore and the Gulf of Mexico. Mr. Brown has served as a director of WGH and WGEH since November 2017.

Mr. Ingram was named Executive Vice President, International, Deepwater and Exploration in May 2018. Prior to this position, he served as Executive Vice President, International & Deepwater Operations and Project Management since October 2017. He joined the Company as Executive Vice President, Global LNG in November 2015. Prior to joining Anadarko, Mr. Ingram was with BG Group since 2006, where he served as a member of the Executive Committee in the role of Executive Vice President—Technical since March 2015. Previously, he held positions of increasing responsibility with the Company's LNG project in Queensland, Australia, where he served as Managing Director of QGC, a BG Group business, since April 2014; as Deputy Managing Director since September 2013; and as Project Director of the Queensland Curtis LNG project since May 2012. From 2006 to May 2012, Mr. Ingram was Asset General Manager of BG Group's Karachaganak interest in Kazakhstan. He joined BG Group after 20 years with Occidental Oil & Gas, where he held several U.K. and international leadership positions in project management, development, and operations. Mr. Ingram has served as a director of WGH and WGEH since November 2018.

Ms. McMillian was named Executive Vice President and General Counsel in August 2018. Prior to this position, she served as Senior Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer since September 2015; Vice President, Deputy General Counsel, Corporate Secretary and Chief Compliance Officer since May 2013; and Deputy General Counsel and Corporate Secretary since July 2012. Ms. McMillian joined Anadarko in December 2004 and has held positions of increasing responsibility with Anadarko, including Vice President, General Counsel and Corporate Secretary of WGH from January 2008 to August 2012. Prior to joining Anadarko, she practiced corporate and securities law at the law firm of Akin Gump Strauss Hauer & Feld LLP, where she represented a variety of clients in a wide range of transactional, corporate governance and securities matters.

Mr. Champion was named Senior Vice President, Chief Accounting Officer and Controller in February 2017. He joined the Company as Vice President, Chief Accounting Officer and Controller in June 2015. Prior to joining Anadarko, Mr. Champion was an Audit Partner with KPMG LLP since October 2003 and served as KPMG's National Audit Leader for Oil and Natural Gas since 2008. He began his career at Arthur Andersen LLP in 1992 before joining KPMG LLP in 2002 as a senior audit manager.

Officers of Anadarko are elected each year at the first meeting of the Board following the annual meeting of stockholders, the next of which is expected to occur on May 14, 2019, and hold office until their successors are duly elected and qualified. There are no family relationships between any directors or executive officers of Anadarko.

Item 1A. Risk Factors

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates, and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties, and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See *Cautionary Statement About Forward-Looking Statements* on page 4 for additional information.

RISK FACTORS

Our business and operations are subject to significant hazards and risks, such as the risks described below. Such risks may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. Each of these risks could adversely affect our business, financial condition and results of operations, as well as adversely affect the value of an investment in our common stock. The following risk factors should be read in conjunction with the other information contained herein, including the consolidated financial statements and the related notes.

Oil, natural-gas, and NGL price volatility, including a substantial or extended decline in the price of these commodities, could adversely affect our financial condition and results of operations.

Prices for oil, natural gas, and NGLs can fluctuate widely. Our revenues, operating results, cash flows from operations, capital budget, and future growth rates are highly dependent on the prices we receive for our oil, natural gas, and NGLs. The markets for oil, natural gas, and NGLs have been volatile historically and may continue to be volatile in the future. Factors influencing the prices of oil, natural gas, and NGLs are beyond our control. These factors include, but are not limited to, the following:

- the domestic and worldwide supply of, and demand for, oil, natural gas, and NGLs
- volatility and trading patterns in the commodity-futures markets
- the cost of exploring for, developing, producing, transporting, and marketing oil, natural gas, and NGLs
- the level of global oil and natural-gas inventories
- weather conditions
- the level of U.S. exports of oil, LNG, or NGLs
- the ability of the members of OPEC and other producing nations to agree to and maintain production levels
- the worldwide military and political environment, civil and political unrest worldwide, including in Africa and the Middle East, uncertainty or instability resulting from the escalation or additional outbreak of armed hostilities, or acts of terrorism in the United States or elsewhere
- the effect of worldwide energy conservation and environmental protection efforts
- the price and availability of alternative and competing fuels
- the level of foreign imports of oil, natural gas, and NGLs
- domestic and foreign governmental laws, regulations, and taxes
- shareholder activism or activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development, and production of oil and natural gas
- the proximity to, and capacity of, natural-gas pipelines and other transportation facilities
- general economic conditions worldwide

The long-term effect of these and other factors on the prices of oil, natural gas, and NGLs is uncertain. Prolonged or substantial decline in these commodity prices may have the following effects on our business:

- adversely affect our financial condition, liquidity, ability to finance planned capital expenditures, ability to repurchase shares, reduce debt and pay dividends, and results of operations
- reduce the amount of oil, natural gas, and NGLs that we can produce economically
- cause us to delay or postpone some of our capital projects
- reduce our revenues, operating income, or cash flows
- reduce the amounts of our estimated proved oil, natural-gas, and NGL reserves
- reduce the carrying value of our oil, natural-gas, and midstream properties due to recognizing additional impairments of proved properties, unproved properties, exploration assets, and midstream facilities
- reduce the standardized measure of discounted future net cash flows relating to oil, natural-gas, and NGL reserves
- limit our access to, or increasing the cost of, sources of capital such as equity and long-term debt
- adversely affect the ability of our partners to fund their working interest capital requirements

We are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner, and feasibility of doing business.

Our operations and properties are subject to numerous laws and regulations governing the release of pollutants or otherwise relating to environmental protection that may be imposed internationally, domestically at the federal, regional, state, tribal and local levels, or by foreign governments. These laws and regulations govern, among other things, the following activities and matters:

- issuance of permits in connection with exploration, drilling, production, produced water disposal, and other upstream and midstream activities
- drilling activities on certain lands lying within wilderness, wetlands, and other protected areas
- types, quantities, and concentrations of emissions, discharges, and authorized releases
- generation, management, and disposition of waste materials
- offshore oil and natural-gas operations and decommissioning of abandoned facilities
- reclamation and abandonment of wells and facility sites
- remediation of contaminated sites
- protection of endangered species

These laws and regulations may impose substantial liabilities for our failure to comply or for any contamination resulting from our operations or any property we've acquired, including the assessment of administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays or cancellations in the permitting, development, or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. Moreover, changes in, or reinterpretations of, environmental laws and regulations governing areas where we operate may adversely impact our operations. Examples of recent proposed and final regulations or other regulatory initiatives include the following:

- *Ground-Level Ozone Standards.* In October 2015, the EPA issued a rule under the Clean Air Act, lowering the National Ambient Air Quality Standard (NAAQS) for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either "attainment/unclassifiable," unclassifiable" or "non-attainment." Additionally, in November 2018, the EPA issued final requirements that apply to state, local, and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. State implementation of the revised NAAQS could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs.
- *Reduction of Methane Emissions by the Oil and Gas Industry.* In June 2016, the EPA published a final rule establishing new emissions standards for methane and additional standards for volatile organic compounds from certain new, modified, and reconstructed oil and natural-gas production and natural-gas processing and transmission facilities. The EPA's rule is under the New Source Performance Standards, Subpart OOOOa, that requires certain new, modified, or reconstructed facilities in the oil and natural-gas sector to reduce these methane

gas and volatile organic compound emissions. These Subpart OOOOa standards expand previously issued New Source Performance Standards, Subpart OOOO, published by the EPA in 2012 by using certain equipment-specific emissions control practices with respect to, among other things, hydraulically fractured oil and natural-gas well completions, fugitive emissions from well sites and compressors, and pneumatic pumps. In February 2018, the EPA finalized amendments to certain requirements of the 2015 final rule, and in September 2018 the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency. Notwithstanding the current uncertainty with these rules establishing emission standards for methane and VOCs and BLM's 2016 final rule to reduce methane emissions from venting, flaring, and leaking from oil and natural-gas operations on public lands, we have taken measures to enter into a voluntary regime, together with certain other oil and natural gas exploration and production operators, to reduce methane emissions. At the state level, some states are considering and others have issued requirements, including Colorado where we conduct operations, for the performance of leak-detection programs that identify and repair methane leaks at certain oil and natural-gas sources. Compliance with these rules or future methane regulations will, among other things, require installation of new emission controls on some of our equipment and increase our capital expenditures and operating costs.

– *Induced Seismic Activity Associated with Oilfield Disposal Wells.* We dispose of wastewater generated from oil and natural-gas production operations directly or through the use of third parties. The legal requirements related to the disposal of wastewater in underground injections wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern relates to seismic events near injection wells used for the disposal of produced water resulting from oil and natural-gas activities. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Colorado developed and follows guidance when issuing underground injection control permits to limit the maximum injection pressure, rate, and volume of water. Texas has also issued rules for wastewater disposal wells that imposed certain permitting and operating restrictions and reporting requirements on disposal wells. In addition, ongoing class action lawsuits, to which we are not currently a party, allege that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulations and restrictions on the use of injection wells by us or by commercial disposal well vendors whom we may use from time to time to dispose of wastewater, which could have a material adverse effect on our capital expenditures and operating costs, financial condition, and results of operations.
– *Reduction of Greenhouse Gas Emissions.* The U.S. Congress and the EPA, in addition to some state and regional authorities, have in recent years considered legislation or regulations to reduce emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. In the absence of federal GHG-limiting legislation, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that, among other things, restrict emissions of GHGs under existing provisions of the U.S. Clean Air Act and may require the installation of "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit a large volume of GHGs together with other criteria pollutants. Also, certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of GHG emissions from specified onshore and offshore production sources. Additionally, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Climate Agreement, an international climate change agreement in Paris, France, that calls for countries to set their own GHG emissions targets and be transparent about the measures that each country will use to achieve its GHG emissions targets. The Paris Climate Agreement entered into force in November 2016. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Climate Agreement, which would result in an effective exit date of November 2020. Notwithstanding any withdrawal from this agreement, the implementation of substantial limitations on GHG emissions in areas where we conduct operations could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves.

These and other regulatory changes could significantly increase our capital expenditures and operating costs or could result in delays to or limitations on our exploration and production activities, which could have an adverse effect on our financial condition, results of operations, or cash flows. For a description of certain environmental proceedings in which we are involved, see Legal Proceedings under Item 3 and Note 18—Contingencies in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Laws and regulations regarding hydraulic fracturing or other oil and natural-gas operations could increase our costs of doing business, result in additional operating restrictions, delays or curtailments, limit the areas in which we can operate, and adversely affect our production.

Hydraulic fracturing is an essential and common practice used to stimulate production of oil and natural gas from dense subsurface rock formations such as shales. We routinely apply hydraulic-fracturing techniques in many of our U.S. onshore oil and natural-gas drilling and completion programs. The process involves the injection of water, sand or alternative proppant, and chemical additives under pressure into a targeted subsurface formation to fracture the surrounding rock and stimulate production.

Hydraulic fracturing onshore in the U.S. is typically regulated by state oil and natural-gas commissions and similar agencies. However, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation, including by federal agencies. For example, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the SDWA involving the use of diesel fuels and published permitting guidance in 2014 addressing the use of diesel in fracturing operations. Additionally, in 2016, the EPA published a final rule under authority of the Clean Water Act prohibiting the discharge of return water recovered from shale natural-gas extraction operations to publicly owned wastewater treatment plants. Also, the BLM published a final rule in 2015 establishing new or more stringent standards for performing hydraulic fracturing on federal and Indian land but the BLM rescinded the 2015 rule in December 2017; however, litigation filed in January 2018 in the federal District Court for the Northern District of California challenging the BLM's decision to repeal 2015 rule remains pending. Also, from time to time, legislation has been introduced, but not enacted, in the U.S. Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In the event that new federal restrictions on the hydraulic-fracturing process are adopted in areas where we operate, we may incur significant additional costs or permitting requirements to comply with such federal requirements, and could experience added delays or curtailment in the pursuit of exploration, development, or production activities.

In addition to asserting regulatory authority, a number of federal entities have reviewed various environmental issues associated with hydraulic fracturing. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances.

Certain states in which we operate, including Colorado, Texas, and Wyoming, have adopted, and other states and local communities are considering adopting, regulations that could impose new or more stringent permitting, disclosure, or other regulatory requirements on hydraulic-fracturing or other oil and natural-gas operations, including subsurface water disposal. For instance, in February 2018, the Colorado Oil & Gas Conservation Commission (COGCC) approved new regulations addressing the operation of flowlines and related infrastructure associated with oil and natural-gas development in the state, including more stringent requirements relating to design, installation, maintenance, testing, tracking, and abandoning of flowlines. The COGCC also approved new regulations in December 2018 enhancing the state's school setback rules by expanding the definition of a school facility and broadening the boundaries. States also could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. In addition to state laws, local land use restrictions, such as city ordinances, may restrict the time, place and manner of drilling in general and/or hydraulic fracturing in particular.

Additionally, certain interest groups in Colorado opposed to oil and natural-gas development generally, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives that, if approved, would revise either statutory law or the state constitution in a manner that would effectively prohibit or make such exploration and production activities in the state more difficult or expensive in the future. For example, in each of the November 2014, 2016 and 2018 general election cycles, ballot initiatives have been pursued, with the 2018 initiative making the November 2018 ballot, seeking to increase setback distances between new oil and natural-gas development and specific occupied structures and/or certain environmentally sensitive or recreational areas that, if adopted, may have had significant adverse impacts on new oil and natural-gas development in the state. However, in each election cycle, the ballot initiative either did not secure a place on the general ballot or, as was the case in November 2018, was defeated. In the event that ballot initiatives, local or state restrictions, or prohibitions are adopted and result in more stringent limitations on the production and development of oil and natural gas in areas where we conduct operations, whether in Colorado or in another state, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the permitting or pursuit of exploration, development, or production activities. In addition, we could possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Such compliance costs and delays, curtailments, limitations, or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Our Tronox settlement may not be deductible for income tax purposes, and we may be required to repay the tax refund of $881 million received in 2016 related to the deduction of the Tronox settlement payment, which may have a material adverse effect on our results of operations, liquidity, and financial condition.

In April 2014, Anadarko and Kerr-McGee Corporation and certain of its subsidiaries (collectively, Kerr-McGee) entered into a settlement agreement for $5.15 billion, resolving all claims that were or could have been asserted in the Tronox Adversary Proceeding. After the settlement became effective in January 2015, we paid $5.2 billion and deducted this payment on our 2015 federal income tax return. Due to the deduction, we had a net operating loss carryback for 2015, which resulted in a tentative tax refund of $881 million in 2016. In our consolidated financial statements, we have recorded an uncertain tax position greater than the amount of the tentative tax refund received.

The IRS has audited our tax position regarding the deductibility of the payment and in September 2018 issued a statutory notice of deficiency rejecting the Company's refund claim. We disagree and filed a petition with the U.S. Tax Court to dispute the disallowance in November 2018. It is possible that we may not ultimately succeed in defending this deduction. If the payment is ultimately determined not to be deductible, we would be required to repay the tentative refund received plus interest and reverse the net benefit of $346 million previously recognized in our consolidated financial statements, which could have a material adverse effect on our results of operations, liquidity, and financial condition. For additional information on income taxes, see *Note 14—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Our debt and other financial commitments may limit our financial and operating flexibility.

At December 31, 2018, our total consolidated debt of $16.4 billion consisted of $11.6 billion related to Anadarko and $4.8 billion related to WES and WGP. We also have various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services and products. Our financial commitments could have important consequences to our business, including, but not limited to, the following:

- increasing our vulnerability to general adverse economic and industry conditions
- limiting our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flows from operations to payments on our debt or to comply with any restrictive terms of our debt
- limiting our flexibility in planning for, or reacting to, changes in the industry in which we operate
- placing us at a competitive disadvantage compared to our competitors that have less debt and/or fewer financial commitments

Additionally, the credit agreement governing the APC RCF contains a number of customary covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65% (excluding the effect of non-cash write-downs), and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. Our ability to meet such covenants may be affected by events beyond our control.

Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control that could cause the quantities and net present value of our reserves to be overstated or understated. The reserves information included or incorporated by reference in this Form 10-K represents estimates prepared by our internal engineers. The procedures and methods for estimating the reserves by our internal engineers were reviewed by independent petroleum consultants; however, no reserves audit was conducted by these consultants. Estimation of reserves is not an exact science. Estimates of economically recoverable oil, natural-gas, and NGL reserves and of future net cash flows depend on a number of variable factors and assumptions, any of which may cause actual results to vary considerably from these estimates. These factors and assumptions may include, but are not limited to, the following:

- estimated future production from an area is consistent with historical production from similar producing areas
- assumed effects of regulation by governmental agencies and court rulings
- assumptions concerning future oil, natural-gas, and NGL prices, future operating costs, and capital expenditures
- estimates of future severance and excise taxes, workover costs, and remedial costs

Estimates of reserves based on risk of recovery and estimates of expected future net cash flows prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenues, and expenditures with respect to our reserves will likely vary from estimates, and the variance may be material. The discounted cash flows included in this Form 10-K should not be construed as the fair value of the estimated oil, natural-gas, and NGL reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the average beginning-of-month prices during the 12-month period for the respective year. Actual future prices and costs may differ materially from the SEC regulation-compliant prices used for purposes of estimating future discounted net cash flows from proved reserves. Therefore, reserves quantities will change when actual prices increase or decrease.

Failure to replace reserves may negatively affect our business.

Our future success depends on our ability to find, develop, or acquire additional oil and natural-gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities, acquire properties containing proved reserves, or both. We may be unable to find, develop, or acquire additional reserves on an economic basis. Furthermore, if oil and natural-gas prices increase, our costs for finding or acquiring additional reserves could also increase.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

As of December 31, 2018, our long-term debt was rated “BBB” by S&P and Fitch with a stable outlook by S&P and a positive outlook by Fitch. Our long-term debt was rated “Ba1” with a stable outlook by Moody’s, which is below investment grade. Subsequent to year end, Moody’s changed its outlook with respect to its rating from stable to positive. Our commercial paper program was rated “A-2” by S&P, “F2” by Fitch, and “NP” by Moody’s. Although we are not aware of any current plans of S&P, Fitch, or Moody’s to lower their respective credit ratings on our long-term debt, we cannot be assured that our credit ratings will not be downgraded. A downgrade in our credit ratings could negatively impact our cost of capital and could also adversely affect our ability to effectively execute aspects of our strategy or to raise debt in the public debt markets. In addition, a downgrade could affect the Company’s requirements to provide financial assurance of its performance under certain contractual arrangements and derivative agreements. For additional information, see *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Our domestic operations are subject to governmental risks that may impact our operations.

Our domestic operations have been, and at times in the future may be, affected by political developments and are subject to complex provincial, federal, regional, state, tribal, local, and other laws and regulations such as restrictions on production, permitting, changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies, price or gathering-rate controls, and hydraulic fracturing, induced seismicity, and environmental protection regulations. To the extent our domestic operations are offshore, we must also comply with requirements focused on oil and natural-gas exploration and production activities in coastal and outer continental shelf (OCS) waters. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals, and certificates from various provincial, federal, regional, state, tribal, and local governmental authorities. We may incur substantial costs to maintain compliance with these existing laws and regulations. In addition, government disruptions, such as an extended federal government shutdown resulting from the failure to pass budget appropriations or adopt continuing funding resolutions could delay or halt the granting and renewal of such permits, approvals, and certificates required to conduct our operations. As a result, activity in the affected regions, such as the Gulf of Mexico and on federal and Indian lands in the United States, could be adversely affected or delayed.

Our domestic midstream operations are subject to governmental risks by federal or state regulators that may impact our operations and revenues.

The Federal Energy Regulatory Commission (FERC) has authority to regulate the rates and terms and conditions of service of natural gas, oil, NGL, and other liquids pipelines operating in interstate commerce. The FERC could exercise jurisdiction over our midstream operations to the extent it determines they operate in interstate commerce. Should we fail to comply with laws the FERC administers, we could be subject to substantial monetary penalties. State regulators in the areas where we have midstream operations may likewise have authority to regulate the rates and terms and conditions of service of, and impose monetary penalties on, our natural gas, oil, NGL, and other liquids pipelines operating in intrastate commerce. To the extent a federal or state regulator imposes rate or service limitations on our midstream operations, it may adversely affect our operations and revenues, either directly or through WES's operations.

Future economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

Historically, concerns about global economic growth, including issues related to tariffs and geopolitical issues, have had a significant adverse impact on global financial markets and commodity prices. Continued concerns could cause demand for petroleum products to diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs and impede the execution of long-term sales agreements or prices thereunder, which are the basis for future LNG production; affect the ability of our vendors, suppliers, and customers to continue operations; and ultimately adversely impact our results of operations, liquidity, and financial condition.

Our business may be adversely affected by deterioration in the credit quality of, or defaults under our contracts with, third parties with whom we do business.

The operation of our business requires us to engage in transactions with numerous counterparties operating in a variety of industries, including other companies operating in the oil and gas industry. These counterparties may default on their obligations to us as a result of operational failures or a lack of liquidity, or for other reasons, including bankruptcy. A default by any of our counterparties may result in our inability to perform obligations under agreements we have made with third parties or may otherwise adversely affect our business or results of operations. For certain assets where we rely on third-party customers for substantially all of our revenues related to those assets, the loss of all or even a portion of the contracted production volume could result in reduced throughput on those systems causing a decline in revenues and the potential impairment of the impacted assets. Furthermore, our rights against any of our counterparties as a result of a default may not be adequate to compensate us for the resulting harm caused or may not be enforceable at all in some circumstances.

We are vulnerable to risks associated with our offshore operations that could negatively impact our operations and financial results.

We conduct offshore operations in the Gulf of Mexico, Ghana, Mozambique, and other countries. Our operations and financial results could be significantly impacted by conditions in some of these areas and are also vulnerable to certain unique risks associated with operating offshore, including those relating to the following:

– hurricanes and other adverse weather conditions
– geological complexities and water depths associated with such operations
– limited number of partners available to participate in projects
– oilfield service costs and availability
– compliance with environmental, safety, and other laws and regulations
– terrorist attacks or piracy
– remediation and other costs and regulatory changes resulting from oil spills or releases of hazardous materials
– failure of equipment or facilities
– response capabilities for personnel, equipment, or environmental incidents

In addition, we conduct some of our exploration in deep waters (greater than 1,000 feet) where operations, support services, and decommissioning activities are more difficult and costly than in shallower waters. The deep waters in the Gulf of Mexico, as well as international deepwater locations, lack the physical and oilfield service infrastructure present in shallower waters. As a result, deepwater operations may require significant time between a discovery and the time that we can market our production, thereby increasing the risk involved with these operations.

Additional domestic and international deepwater drilling laws, regulations and other restrictions; delays in the processing and approval of drilling permits and exploration, development, oil spill-response and decommissioning plans; and other offshore-related developments may have a material adverse effect on our business, financial condition, or results of operations.

The BOEM and the BSEE have imposed more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. Compliance with these more stringent regulatory requirements and with existing environmental and oil spill regulations, together with any uncertainties or inconsistencies in decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts.

Additionally, these governmental agencies are continuing to evaluate and develop and implement new, more restrictive requirements that could result in additional costs, delays, restrictions, or obligations with respect to oil and natural-gas exploration and production operations conducted offshore. For example, in April 2016, the BSEE published a final rule on well control that, among other things, imposes rigorous standards relating to the design, operation and maintenance of blowout preventers, real-time monitoring of deepwater and high temperature, high pressure drilling activities, and enhanced reporting requirements. In May 2018, however, the BSEE issued a proposed rule, which has not been finalized, to revise these regulations for well control.

Moreover, in September 2016, the BOEM issued a Notice to Leaseholders (NTL) that would bolster supplemental bonding procedures for the decommissioning of offshore wells, platforms, pipelines, and other facilities; however, since the BOEM's issuance of the NTL, the agency has delayed indefinitely, beyond June 30, 2017, the implementation timeline of the NTL for most of those facilities so that BOEM could further assess this financial assurance program, but this delay is expected to be temporary. Following completion of its review, the BOEM may elect to retain the September 2016 NTL in its current form or may make revisions thereto and, thus, until the review is completed and the BOEM determines what additional financial assurance may be required by us, we cannot provide any assurance of the amount of any additional financial assurance, which may be material, that may be ordered by the BOEM and required in any proposed tailored plan that we may submit to the BOEM in the future for approval, or that such additional financial assurance amounts can be obtained.

These regulatory actions, or any new rules, regulations or legal initiatives, could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs and limit activities in certain areas, or cause us to incur penalties, fines or shut-in production at one or more of our facilities or result in the suspension or cancellation of leases. Moreover, under existing BOEM and BSEE rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interests may be held jointly and severally liable for decommissioning of OCS facilities existing at the time the assignment was approved by the BOEM, in the event that the assignee or any subsequent assignee is unable or unwilling to conduct required decommissioning. In the event that we, in the role of assignor, receive orders from the BSEE to decommission OCS facilities that one of our assignees, or a subsequent assignee, of offshore facilities is unwilling or unable to perform, we could incur costs to perform those decommissioning obligations, which costs could be material.

In addition, our offshore development activities rely on subcontractors to perform certain offshore construction and installation activities. The Jones Act requires that vessels engaged in U.S. coastwise trade be built in the United States, registered under the U.S. flag, manned by predominantly U.S. crews, and owned and operated by U.S. citizens within the meaning of the Jones Act. Under existing U.S. Customs & Border Protection (CBP) rulings, the Jones Act is not applicable to foreign vessels conducting certain construction and pipeline installation activities on the OCS. Recently, the U.S. Marine Vessel Owners Association filed a lawsuit seeking to compel CBP to revoke a number of long-standing ruling letters relating to this exemption. The outcome of this litigation is uncertain. However, if the litigation is successful and the rulings are revoked, foreign flagged vessels could no longer perform certain operations for us in compliance with the Jones Act. The existing fleet of U.S. vessels are currently incapable of performing these construction and installation activities. As a result, certain of our development efforts could be delayed, disrupted or even suspended.

Also, if material spill events were to occur in the future, the United States or other countries where such an event were to occur could issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural-gas exploration and development. We cannot predict with any certainty the full impact of any new laws, regulations, or legal initiatives on our drilling operations or on the cost or availability of insurance to cover the risks associated with such operations. The overall costs to implement and complete any such spill response activities or any decommissioning obligations could exceed estimated accruals, insurance limits, or supplemental bonding amounts, which could result in the incurrence of additional costs to complete.

Further, the deepwater Gulf of Mexico (as well as international deepwater locations) lacks the degree of physical and oilfield service infrastructure present in shallower waters. Therefore, despite our oil spill-response capabilities, it may be difficult for us to quickly or effectively execute any contingency plans related to potential material deepwater events in the future.

The matters described above, individually or in the aggregate, could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

We operate in foreign countries and are subject to political, economic, and other uncertainties.

We have operations outside the United States, including in Algeria, Ghana, Mozambique, Colombia, Peru, and other countries. As a result, we face political and economic risks and other uncertainties with respect to our international operations. These risks may include the following, among other things:

- loss of revenue, property, and equipment or delays in operations as a result of hazards such as expropriation, war, piracy, acts of terrorism, insurrection, civil unrest, and other political risks, including tension and confrontations among political parties
- transparency issues in general and, more specifically, the U.S. Foreign Corrupt Practices Act, the U.K. Bribery Act, and other anti-corruption compliance laws and issues
- increases in taxes and governmental royalties
- unilateral renegotiation of contracts by governmental entities
- redefinition of international boundaries or boundary disputes
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations
- difficulties enforcing our rights against a governmental agency in the absence of an appropriate and adequate dispute resolution mechanism to address contractual disputes, such as international arbitration
- changes in laws and policies governing operations of foreign-based companies
- foreign-exchange restrictions
- international monetary fluctuations and changes in the relative value of the U.S. dollar as compared to the currencies of other countries in which we conduct business

Outbreaks of civil and political unrest and acts of terrorism have occurred in countries in Europe, Africa, South America, and the Middle East, including countries close to or where we conduct operations. Continued or escalated civil and political unrest and acts of terrorism in the countries in which we operate could result in our curtailing operations or delays in project completions. In the event that countries in which we operate experience civil or political unrest or acts of terrorism, especially in events where such unrest leads to an unseating of the established government, our operations could be materially impaired.

Our international operations may also be adversely affected, directly or indirectly, by laws, policies, and regulations of the United States affecting foreign trade and taxation, including U.S. trade sanctions.

Realization of any of the factors listed above could materially and adversely affect our financial condition, results of operations, or cash flows.

The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, or qualified personnel. The cost for such items may increase as a result of a variety of factors beyond our control, such as increases in the cost of electricity, steel, and other raw materials that we and our vendors rely upon; increased demand for labor, services, and materials as drilling activity increases; and increased taxes. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Deterioration in the credit or equity markets could adversely affect us.

We have exposure to different counterparties. For example, we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, investment funds, and other institutions. These transactions expose us to credit risk in the event of default by our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill existing obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions through our derivative transactions. In addition, if any lender under our credit facilities is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facilities. Moreover, to the extent that purchasers of our production rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to us if such purchasers were unable to access the credit or equity markets for an extended period of time.

Exploration, development, and production activities carry inherent risk. These activities could result in liability exposure or the loss of production and revenues. In addition, we are not insured against all of the operating risks to which our business is exposed.

Our business is subject to all of the hazards and operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and natural gas, including blowouts; cratering and fire; environmental hazards such as natural-gas leaks, oil spills, pipeline and vessel ruptures, and releases of chemicals or other hazardous substances, any of which could result in damage to, or destruction of, oil and natural-gas wells or formations, production facilities, and other property; pollution or other environmental damage; and injury to persons. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, resulting in loss of equipment or otherwise negatively impacting the projected economic performance of our projects. Any of these risks or hazards can result in injuries and/or deaths of employees, supplier personnel or other individuals, loss of hydrocarbons, environmental pollution and other damage to our properties or the properties of others, regulatory investigations, litigation, fines, and penalties or restricted access to our properties.

For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/loss of control of a well, comprehensive general liability, aviation liability, and worker's compensation and employer's liability. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing and for certain risks, such as political risk, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business such as hurricanes. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our financial condition, results of operations, or cash flows.

Our commodity-price risk-management and trading activities may prevent us from fully benefiting from price increases and may expose us to regulatory and other risks.

To the extent that we engage in commodity-price risk-management activities to protect our cash flows from commodity-price declines, we may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our commodity-price risk-management and trading activities may expose us to the risk of financial loss in certain circumstances, including instances in which the following occur:

- our production is less than the notional volume
- a widening of price basis differentials occurs between delivery points for our production and the delivery point assumed in the derivative arrangement
- the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements
- a sudden unexpected event materially impacts oil, natural-gas, or NGL prices

We are required to observe the market-related regulations enforced by the Commodity Futures Trading Commission and other agencies with regard to our commodity-price risk-management activities, which hold substantial enforcement authority. Failures to comply with such regulations, as interpreted and enforced, could materially and adversely affect our results of operations and financial condition.

Material differences between the estimated and actual timing of critical events may affect the completion, cost and commencement of production from development projects.

We are involved in certain large development projects and the completion of those projects may be delayed beyond our anticipated completion dates. Key factors that may affect the timing and outcome of such projects include the following:

– project approvals and funding by joint-venture partners
– timely issuance of permits and licenses by governmental agencies or legislative and other governmental approvals
– weather conditions
– availability of qualified personnel
– civil and political environment of, and existing infrastructure in, the country or region in which the project is located
– manufacturing and delivery schedules of critical equipment
– commercial arrangements for pipelines, tankers, and related equipment to transport and market hydrocarbons

Delays and differences between estimated and actual timing of critical events may affect the forward-looking statements related to large development projects. If we are unable to complete such projects at their expected costs and in a timely manner, our financial condition, results of operations, or cash flows could be materially and adversely effected.

The oil and gas exploration and production industry is very competitive, and some of our exploration and production competitors have greater financial and other resources than we do.

The oil and gas business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of oil and gas production. Our competitors include national oil companies, major integrated oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies as well as participants in other industries supplying energy and fuel to consumers. Some of our competitors may have greater and more diverse resources on which to draw than we do. If we are not successful in our competition for oil and gas reserves or in our marketing of production, our financial condition and results of operations may be adversely affected.

Our drilling activities may not encounter commercially productive oil or natural-gas reservoirs.

Drilling for oil and natural gas involves numerous risks, including the risk that we will not encounter commercially productive oil or natural-gas reservoirs. Drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including the following:

– unexpected drilling conditions
– pressure or irregularities in formations
– equipment failures or accidents
– fires, explosions, blowouts, and surface cratering
– marine risks such as capsizing, collisions, and hurricanes
– difficulty identifying and retaining qualified personnel
– title problems
– other adverse weather conditions
– lack of availability or delays in the delivery of technology, equipment, or resources for operations

Certain of our future drilling activities may not be successful and, if unsuccessful, could result in a material adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because a portion of our capital budget is devoted to higher-risk exploratory projects, it is likely that we will continue to experience significant exploration and dry hole expenses.

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

Other companies operate some of the properties in which we have an interest. We have limited ability to influence the operation or future development of these nonoperated properties or the amount or timing of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working-interest owners for these projects and our limited ability to influence the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital, adversely affect the timing of activities, or lead to unexpected future costs, including costs associated with the hazards and operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and natural gas, including blowouts; cratering and fire; environmental hazards such as natural-gas leaks, oil spills, pipeline and vessel ruptures, and releases of chemicals or other hazardous substances.

Our ability to sell and deliver our oil, natural-gas, and NGL production could be materially harmed if adequate gathering, processing, compression, transportation, and disposal facilities and equipment are unavailable.

The marketability of our production depends in part on the availability, proximity, and capacity of gathering, processing, compression, transportation, tankers, pipeline, and produced water facilities. These facilities may be temporarily unavailable to us due to market conditions, regulatory reasons, mechanical reasons or other factors or conditions. If any pipelines or tankers become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport the oil, natural gas, and NGLs, which could increase our costs and/or reduce the revenues we might obtain from the sale of the oil and natural-gas. In addition, in certain newer plays, the capacity of gathering, processing, compression, transportation, and disposal facilities and equipment may not be sufficient to accommodate potential production from existing and new wells. Construction and permitting delays, permitting costs and regulatory or other constraints could limit or delay the construction, manufacture or other acquisition of new gathering, processing, compression, transportation, and disposal facilities and equipment, and we may experience delays or increased costs in accessing the pipelines, gathering systems or rail systems necessary to transport our production to points of sale or delivery or disposing of produced water.

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

Our results of operations could be adversely affected by goodwill impairments.

As a result of mergers and acquisitions, we had approximately $4.8 billion of goodwill on our Consolidated Balance Sheet at December 31, 2018. Goodwill must be tested at least annually for impairment, and more frequently when circumstances indicate likely impairment. Goodwill is considered impaired to the extent that its carrying amount exceeds its implied fair value. Various factors could reduce the fair value of a reporting unit such as our inability to replace the value of our depleting asset base, difficulty or potential delays in obtaining drilling permits, or other adverse events such as lower oil and natural-gas prices, which could lead to an impairment of goodwill. An impairment of goodwill could have a substantial negative effect on our reported earnings.

Risks related to acquisitions and divestitures may adversely affect our business, financial condition, and results of operations.

Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about, among other things, reserves, estimated production, revenues, capital expenditures, operating expenses, and costs
- the assumption of environmental, decommissioning, and other liabilities, and losses or costs for which we are not indemnified or for which our indemnity is inadequate
- a failure to attain or maintain compliance with environmental, safety, and other governmental regulations

In addition, from time to time, we may sell or otherwise dispose of certain of our properties as a result of an evaluation of our asset portfolio and to help enhance our liquidity. These transactions also have inherent risks, including:

- possible delays in closing
- lower-than-expected sales proceeds for the disposed assets
- potential post-closing claims for indemnification

Moreover, the agreements relating to these transactions contain provisions pursuant to which liabilities related to past and future operations, such as matters of litigation, environmental contingencies, royalty obligations and income taxes, have been allocated between the parties by means of liability assumptions, indemnities, escrows, trusts and similar arrangements. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release the Company from guarantees or other credit support provided prior to the sale of the divested assets. In addition, one or more of the parties in these transactions could fail to perform its obligations under the agreements as a result of financial distress. In the event that any such counterparty were to become the subject of a case proceeding under Title 11 of the U.S. Bankruptcy Code or any other insolvency law or similar law, the counterparty may not perform its obligations under the agreement and we may be responsible for the cost of the obligations assumed by the counterparties. As a result, after a divestiture, the Company may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

If any of these risks materialize, the benefits of such acquisition or divestiture may not be fully realized, if at all, and our business, financial condition, and results of operations could be negatively impacted.

Our business could be negatively affected by security threats, including cyber threats, and other disruptions.

As an oil and gas producer, we face various security threats, including cyber threats such as attempts to gain unauthorized access to, or control of, sensitive information or to render data or systems corrupted or unusable; threats to the security of our facilities and infrastructure or those of third parties such as processing plants and pipelines; and threats from terrorist acts. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure may result in increased costs. In addition, our business has become increasingly dependent on digital technologies and we anticipate expanding our use of technology in our operations, including through data analytics and process automation. Further, we have exposure to cyber incidents and the negative impacts of such incidents related to our critical data and proprietary information housed on third-party information technology systems, including the cloud. Our vendors and other business partners may also separately suffer disruptions or breaches from cyber attacks which could adversely impact our operations and compromise our information. We continuously work to install new, and upgrade existing, information technology systems and provide employee awareness training on phishing, malware, and other cyber risks to help ensure that we are protected, to the extent possible, against cyber risks and security breaches. We also perform periodic drills for responding to cyber incidences. There can be no assurance that such safeguards, procedures, and controls will be sufficient to prevent security breaches from occurring. Cyber attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to, or control of our data, systems, or facilities, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data or systems, which could have an adverse effect on our reputation, financial condition, results of operations, or cash flows.

While we have experienced cyber attacks, we have not suffered any material losses relating to such attacks; however, there is no assurance that we will not suffer such losses in the future. We could incur substantial remediation and other costs or suffer other negative consequences, including litigation risks. In addition, as cyber threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cyber vulnerabilities.

Provisions in our corporate documents and Delaware law could delay or prevent a change of control of Anadarko, even if that change would be beneficial to our stockholders.

Our restated certificate of incorporation and by-laws contain provisions that may make a change of control of Anadarko difficult, even if it may be beneficial to our stockholders, including provisions governing the nomination and removal of directors, the prohibition of stockholder action by written consent and regulation of stockholders' ability to bring matters for action before annual stockholder meetings, and the authorization given to our Board of Directors to issue and set the terms of preferred stock.

In addition, Section 203 of the Delaware General Corporation Law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock.

We may reduce or cease to pay dividends on our common stock.

We can provide no assurance that we will continue to pay dividends at the current rate or at all. As of February 2019, our quarterly dividend was $0.30 per share. The amount of cash dividends, if any, to be paid in the future is determined by our Board of Directors based on our financial condition, results of operations, cash flows, levels of capital and exploration expenditures, future business prospects, expected liquidity needs, and other matters that our Board of Directors deems relevant.

Difficulty attracting and retaining experienced technical personnel could reduce our competitiveness and prospects for future success.

Our exploratory drilling success and the success of other development and operating activities depends, in part, on our ability to attract and retain experienced explorationists, engineers, and other professionals. Competition for such professionals could be intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

The Company is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business, including personal injury and death claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas exploration, development, production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, tribal, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's financial condition, results of operations, or cash flows.

WGR Operating, LP, a subsidiary of the Company, is currently in negotiations with the EPA with respect to alleged noncompliance with the leak detection and repair requirements of the Clean Air Act at its Granger, Wyoming facilities. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

In September 2018, Anadarko E&P Onshore LLC, a subsidiary of the Company, entered into a final consent assessment with the Pennsylvania Department of Environmental Protection resolving issues concerning enforcement over a produced water release in Pennsylvania in 2015 and agreed to pay a penalty of $350,000.

Kerr-McGee Oil and Gas Onshore, LP, a subsidiary of the Company, is currently in negotiations with the State of Colorado's Department of Public Health and Environment with respect to alleged noncompliance with the Colorado Air Quality Control Commission's Regulations. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

Kerr-McGee Gathering, LLC, a subsidiary of the Company, is currently in negotiations with the EPA and the Department of Justice with respect to alleged noncompliance with the leak detection and repair requirements of the Clean Air Act at its Fort Lupton complex in Colorado. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

See *Note 18—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, which is incorporated herein by reference, for a discussion of material legal proceedings to which the Company is a party.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

MARKET INFORMATION, HOLDERS, AND DIVIDENDS

At January 31, 2019, there were approximately 9,074 holders of record of Anadarko common stock. The common stock of Anadarko is traded on the New York Stock Exchange under the symbol "APC".

The amount of future dividends paid to Anadarko common stockholders is determined by the Board on a quarterly basis and is based on the Company's earnings, financial condition, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors deemed relevant by the Board. In November 2018, the Company announced an increase in the quarterly dividend to $0.30 from $0.25 per share of common stock. For additional information, see *Liquidity and Capital Resources—Financing Activities—Common Stock Dividends* and *Distributions to Noncontrolling Interest Owners* under Item 7 of this Form 10-K.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following sets forth information with respect to the equity compensation plans available to directors, officers, and employees of the Company at December 31, 2018:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders	6,356,970	$ 67.00	20,246,444
Equity compensation plans not approved by security holders	—	—	—
Total	6,356,970	$ 67.00	20,246,444

PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PERSONS

The following sets forth information with respect to repurchases made by the Company of its shares of common stock during the fourth quarter of 2018:

Period	Total number of shares purchased [1]	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs[2]	Approximate dollar value of shares that may yet be purchased under the plans or programs [2][3]
October 1-31, 2018	35,626	$ 64.55	—	$ 500,000,003
November 1-30, 2018	56,912	$ 55.73	—	$ 1,500,000,003
December 1-31, 2018	4,792,707	$ 52.35	4,776,318	$ 1,250,000,064
Total	4,885,245	$ 52.48	4,776,318	

(1) During the fourth quarter of 2018, 109 thousand shares were repurchased related to stock received by the Company for the payment of withholding taxes due on employee share issuances under share-based compensation plans. For additional information, see Note 23—Share-Based Compensation in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(2) During the fourth quarter of 2018, under the Share Repurchase Program, the Company repurchased 4.8 million shares of common stock in the open market for $250 million. For additional information, see Note 21—Stockholders' Equity in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

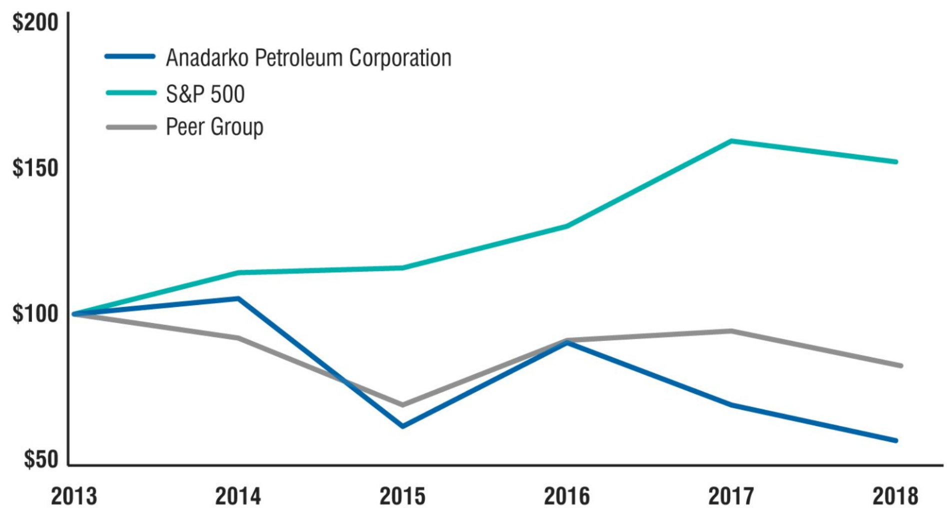
(3) The Company announced a $2.5 billion Share-Repurchase Program in September 2017, which was expanded to $3.0 billion in February 2018 and $4.0 billion in July 2018. In November 2018, the program was further expanded to $5.0 billion and extended through June 30, 2020. For additional information, see Note 21—Stockholders' Equity in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

PERFORMANCE GRAPH

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

The following graph compares the cumulative five-year total return to stockholders of Anadarko's common stock relative to the cumulative total returns of the S&P 500 index and a peer group of 11 companies. The companies included in the peer group are Apache Corporation; Chesapeake Energy Corporation; Chevron Corporation; ConocoPhillips; Devon Energy Corporation; EOG Resources, Inc.; Hess Corporation; Marathon Oil Corporation; Noble Energy, Inc.; Occidental Petroleum Corporation; and Pioneer Natural Resources Company.

Comparison of 5-Year Cumulative Total Return Among
Anadarko Petroleum Corporation, the S&P 500 Index, and a Peer Group



An investment of $100 (with reinvestment of all dividends) is assumed to have been made in the Company's common stock, in the S&P 500 Index, and in the peer group on December 31, 2013, and its relative performance is tracked through December 31, 2018.

Fiscal Year Ended December 31	2013	2014	2015	2016	2017	2018
Anadarko Petroleum Corporation	$ 100.00	$ 105.14	$ 62.88	$ 90.58	$ 69.96	**$ 58.19**
S&P 500	100.00	113.69	115.26	129.05	157.22	**150.33**
Peer Group	100.00	92.09	69.98	91.31	94.42	**82.93**

Item 6. Selected Financial Data

	Summary Financial Information [1]				
millions except per-share and employee amounts	**2018**	2017	2016	2015	2014
Sales Revenues [6]	**$ 13,070**	$ 10,969	$ 8,447	$ 9,486	$ 16,375
Gains (Losses) on Divestitures and Other, net	**312**	939	(578)	(788)	2,095
Total Revenues and Other	**13,382**	11,908	7,869	8,698	18,470
Operating Income (Loss)	**2,619**	(565)	(2,372)	(8,743)	5,438
Net Income (Loss) [2]	**752**	(211)	(2,808)	(6,812)	(1,563)
Net Income (Loss) Attributable to Common Stockholders	**615**	(456)	(3,071)	(6,692)	(1,750)
Per Common Share (amounts attributable to common stockholders)					
Net Income (Loss)—Basic	**$ 1.20**	$ (0.85)	$ (5.90)	$ (13.18)	$ (3.47)
Net Income (Loss)—Diluted	**$ 1.20**	$ (0.85)	$ (5.90)	$ (13.18)	$ (3.47)
Dividends	**$ 1.05**	$ 0.20	$ 0.20	$ 1.08	$ 0.99
Average Number of Common Shares Outstanding—Basic	**504**	548	522	508	506
Average Number of Common Shares Outstanding—Diluted	**504**	548	522	508	506
Net Cash Provided by (Used in) Operating Activities [3]	**$ 5,929**	$ 4,009	$ 3,000	$ (1,877)	$ 8,466
Net Cash Provided by (Used in) Investing Activities	**(5,982)**	(1,030)	(2,742)	(4,771)	(6,472)
Net Cash Provided by (Used in) Financing Activities	**(3,177)**	(1,613)	2,008	220	1,675
Capital Expenditures	**$ 6,185**	$ 5,300	$ 3,314	$ 5,888	$ 9,256
Long-term debt - Anadarko [4]	**$ 10,683**	$ 12,054	$ 12,162	$ 12,945	$ 12,595
Long-term debt - WES and WGP	**4,787**	3,493	3,119	2,691	2,409
Total Stockholders' Equity	**8,496**	10,696	12,212	12,819	19,725
Total Assets	**$ 40,376**	$ 42,086	$ 45,564	$ 46,331	$ 60,879
Annual Sales Volume					
Oil (MMBbls)	**141**	129	116	116	106
Natural Gas (Bcf)	**390**	478	766	852	945
Natural-Gas Liquids (MMBbls)	**37**	36	46	47	44
Total (MMBOE) [5]	**243**	245	290	305	308
Average Daily Sales Volume					
Oil (MBbls/d)	**385**	355	316	317	292
Natural Gas (MMcf/d)	**1,069**	1,309	2,093	2,334	2,589
Natural-Gas Liquids (MBbls/d)	**103**	99	128	130	119
Total (MBOE/d) [5]	**666**	672	793	836	843
Proved Reserves					
Oil Reserves (MMBbls)	**667**	658	702	713	929
Natural-gas Reserves (Tcf)	**3.2**	3.2	4.4	6.0	8.7
Natural-gas Liquids Reserves (MMBbls)	**268**	243	283	340	479
Total Proved Reserves (MMBOE) [5]	**1,473**	1,439	1,722	2,057	2,858
Number of Employees	**4,700**	4,400	4,500	5,800	6,100

(1) Consolidated for Anadarko and its subsidiaries. Certain amounts for prior years have been reclassified to conform to the current presentation.
(2) Includes a $1.2 billion one-time deferred tax benefit in 2017 related to Tax Reform Legislation and a $4.4 billion Tronox-related contingent loss in 2014.
(3) Includes Tronox settlement payment of $5.2 billion in 2015.
(4) Excludes WES and WGP.
(5) Natural gas is converted to equivalent barrels at the rate of 6,000 cubic feet of gas per barrel.
(6) 2018 includes impact of adopting ASU 2014-09. See *Note 2—Revenue from Contracts with Customers*.

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

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this Form 10-K in Item 8, and the information set forth in *Risk Factors* under Item 1A.

MANAGEMENT OVERVIEW

Anadarko’s strategic objectives are to explore for, develop, and commercialize resources globally; ensure health, safety, and environmental excellence; focus on financial discipline, flexibility, and value creation; and demonstrate the Company’s core values in all its business activities. The Company’s revenues, operating results, cash flows from operations, capital spending, and future growth rates are highly dependent on commodity prices, which affect the value the Company receives from its sales of oil, natural gas, and NGLs.

The Company continues to efficiently allocate capital in order to generate attractive returns on, and of, capital while investing within cash flow. Anadarko also continues to focus on cash-margin improvement and has actively managed its portfolio to focus on higher-return, oil-levered opportunities in areas where it possesses both scale and competitive advantages, namely in the Delaware and DJ basins in the U.S. onshore and in the deepwater Gulf of Mexico. The Company plans to deploy a portion of its cash flow generated from its Gulf of Mexico, Algeria, Ghana, and DJ basin assets to fund investments in other assets that generate attractive cash returns, thereby improving the Company’s overall long-term cash-flow profile and ability to continue returning cash to investors.

2019 Outlook

The Company plans to continue focusing on returning capital directly to its investors. The Company demonstrated this focus in 2018 by increasing its quarterly cash dividend from $0.05 to $0.30 per share, expanding its authorized Share-Repurchase Program to $5 billion, and increasing its debt-reduction program to $2 billion. As of December 31, 2018, the Company had repurchased 65 million shares of its common stock for an average price of $57.69 per share. The Company expects to complete the remaining $1.25 billion of authorized share repurchases by mid-year 2020. As of December 31, 2018, Anadarko had retired more than $600 million of debt and plans to repay $900 million of debt maturing in the first half of 2019. An additional $500 million of debt reduction is anticipated through mid-year 2020. These actions demonstrate the cash-flow-generating strength of the Company’s asset portfolio and the Company’s ongoing commitment to capital efficiency and returns.

At the end of 2018, the Company announced the planned contribution and sale of substantially all of its midstream assets not owned by WES, which are largely associated with Anadarko's two premier U.S. onshore oil plays in the Delaware and DJ basins, to WES for approximately $4.0 billion, with approximately $2.0 billion of cash proceeds and the balance to be paid in WES common units. This transaction is expected to increase WES’s cash distributions paid to Anadarko in 2019 and reduce Anadarko’s future midstream capital funding requirements associated with the divested assets. Additionally, WES announced that a wholly owned subsidiary of WGP will merge with and into WES to simplify its structure and lower the weighted-average cost of capital for the midstream entity via the elimination of incentive distribution rights. These transactions are expected to close in the first quarter of 2019 and should result in enhanced liquidity of Anadarko’s residual ownership of WGP securities.

The Company's 2019 capital program is consistent with the Company's focus on enhancing shareholder value by delivering attractive cash returns on invested capital in a $50 oil (for both WTI and Brent) and $3 natural-gas (Henry Hub) price environment while advancing the development of the Company's core assets. Anadarko currently estimates a 2019 capital spending range of $4.3 billion to $4.7 billion, excluding WES. Anadarko expects to allocate approximately 70% of this 2019 capital investment to the U.S. onshore upstream and midstream resource plays; 16% to conventional oil plays in the deepwater Gulf of Mexico, Algeria, and Ghana; 10% to future value areas, which includes 6% to exploration and 4% to Mozambique LNG activities, excluding post-FID incremental spend; and 4% to corporate activities. The Company's asset footprint and strong balance sheet are intended to perform through commodity cycles.

– ***Delaware Basin*** Anadarko plans to allocate approximately $1.4 billion toward upstream activities. The successful expansion of the Company's infrastructure footprint, including oil gathering and treating facilities throughout West Texas, is paving the way to transition to multi-well pad development. This phased development approach is expected to deliver incremental oil sales volume in 2019.

– ***DJ Basin*** Anadarko expects to invest approximately $1.3 billion on upstream activities, with continued development of its minerals-interest ownership and infrastructure-advantaged position in the Wattenberg field. Anadarko expects to deliver incremental oil sales volume from the DJ basin in 2019.

– ***Powder River Basin*** Anadarko expects to invest approximately $250 million toward upstream activities, including appraisal and delineation of its 300,000 gross acre position in the southern Powder River basin primarily targeting the Turner formation.

– ***Gulf of Mexico*** Anadarko expects to allocate approximately $500 million toward its deepwater Gulf of Mexico operations. Although the capital allocation is lower than in 2018, the Company plans to deliver a similar number of wells in 2019 and maintain production levels around 140 MBOE/d. The majority of these investments are expected to be directed toward high-return oil development opportunities near operated infrastructure at Constellation, Holstein, Horn Mountain, K2, Lucius, and North Hadrian.

– ***International*** Anadarko plans to allocate approximately $200 million toward its international operations in Algeria and Ghana. The investment in Ghana will be focused on adding incremental wells to optimize capacity at the Jubilee and TEN FPSO vessels.

– ***Exploration*** The Company's exploration investments in 2019 are expected to total approximately $250 million. Exploration spending will primarily be focused on identifying material and scalable opportunities in the U.S. onshore and tie-back opportunities near existing operated facilities in the deepwater Gulf of Mexico.

– ***LNG*** The Company expects to invest approximately $200 million in the Mozambique LNG project in 2019 on pre-FID activities. This includes Anadarko's portion of the cost associated with ongoing site preparation for the shared onshore facilities. The Company remains on track for making a final investment decision in the first half of 2019, and anticipates adjusting its capital investment expectations associated with the Mozambique LNG project if the project is sanctioned.

WES currently estimates a 2019 total capital spending range of $1.3 to $1.4 billion. WES capital investment will be primarily focused in the DJ and Delaware basins, with over 90% of the estimated 2019 total capital expenditures allocated to these two basins.

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Significant 2018 Operating and Financial Activities

Total Company

- The Company's oil sales volume averaged 385 MBbls/d, representing a 9% increase from 2017, primarily due to increased volume from the DJ and Delaware basins, partially offset by the divestiture of certain U.S. onshore assets in 2017.
- The Company's overall oil sales-volume product mix increased to 58% in 2018, compared to 53% in 2017. The overall liquids sales-volume product mix increased to 73% in 2018, compared to 67% in 2017.

U.S. Onshore

- Total sales volume in the Delaware basin averaged 109 MBOE/d, representing a 68% increase from 2017, and oil sales volume in the Delaware basin increased 27 MBbls/d, representing a 71% increase from 2017, primarily due to continued drilling and completion activities.
- In the Delaware basin, the Reeves and Loving County ROTFs were completed, with 138 total wells flowing into the facilities by the end of 2018. In addition, the first train at the WES-owned Mentone natural-gas processing plant was placed in service during the fourth quarter, adding 200 MMcf/d of natural-gas processing capacity.
- Oil sales volume in the DJ basin increased 14 MBbls/d, representing a 17% increase from 2017, primarily due to continued drilling and completion activities.
- In the DJ basin, the sixth COSF train was placed in service, adding 30 MBbls/d of oil-stabilization capacity.
- The Company received net proceeds of approximately $370 million from the divestiture of its nonoperated interest in Alaska.

Gulf of Mexico

- Oil sales volume averaged 121 MBbls/d, remaining relatively flat compared to 2017, primarily due to natural production declines and planned downtime at various platforms, partially offset by new wells coming online at Horn Mountain, Holstein, Marlin, and Caesar Tonga.

Ghana

- In the TEN field, the operator resumed drilling operations in early 2018, with one well brought online in 2018. Two additional wells were drilled in 2018, with completion activities ongoing at year end.
- In the Jubilee field, the operator drilled two production wells during the second quarter of 2018, with the first of these wells brought online in the third quarter. The second well was brought online in the fourth quarter. Additionally, a previously drilled water injector well was brought online during the fourth quarter of 2018.
- The operator of the Jubilee FPSO completed two shutdowns to effectively stabilize the turret and rotate the FPSO to its permanent heading. Completion of the spread-mooring anchoring system is expected in early 2019, with no further shutdowns anticipated.

Mozambique

- During 2018 and subsequent to year end, additional LNG sales and purchase agreements were executed, increasing contracted volumes to more than 7.5 MTPA, with an additional 2.0 MTPA of contracted volume anticipated prior to FID.
- The Government of Mozambique approved the Development Plan for the Anadarko-operated, initial two-train Golfinho/Atum project.
- The preferred offshore construction and installation contractor was selected in the fourth quarter of 2018, and the contracts with the onshore and offshore construction and installation contractors are being finalized ahead of making a final investment decision in the first half of 2019.
- Site preparation activities are fully underway at the Afungi onshore site, as major infrastructure and resettlement projects are proceeding as planned, positioning the area for construction of the LNG facilities.
- In the third quarter of 2018, Offshore Area 4, which is owned and operated by third parties, joined the Anadarko-led resettlement and airstrip projects as a 50% participant.

Financial

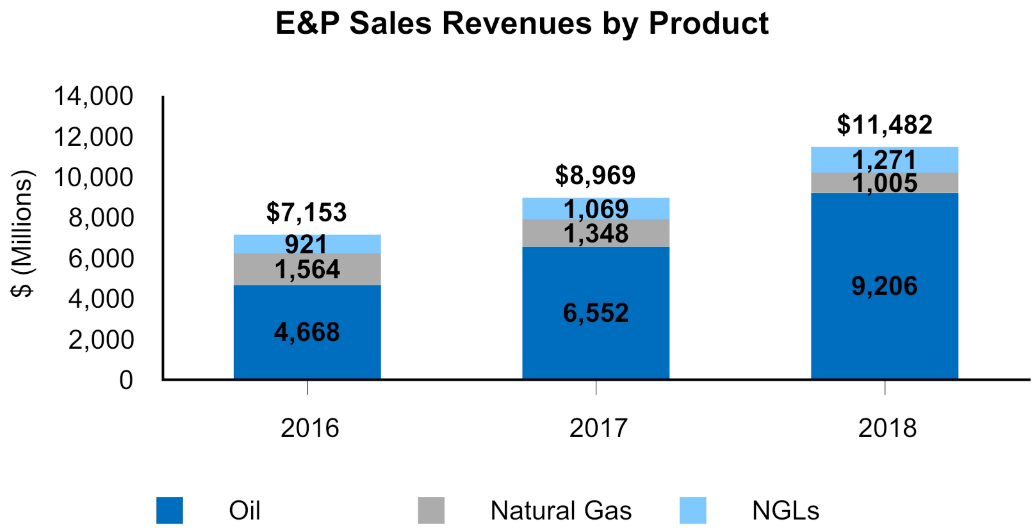
- The Company generated $5.9 billion of cash flow from operations and ended 2018 with $1.3 billion of cash.
- The Company completed $2.7 billion of share repurchases and retired more than $600 million of debt.

FINANCIAL RESULTS

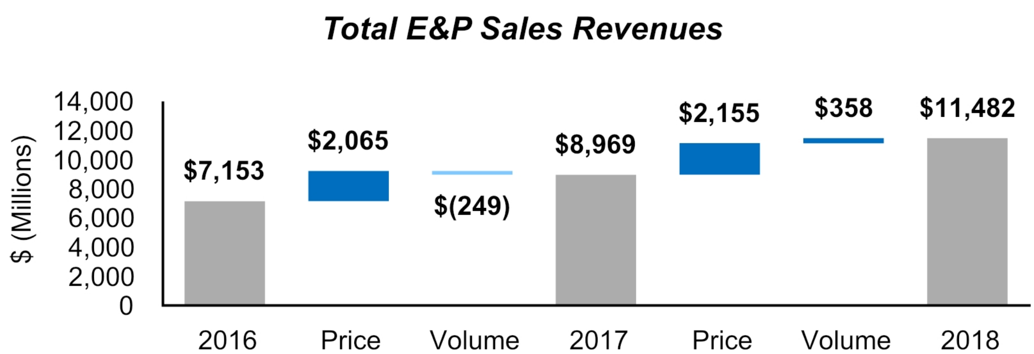
millions except per-share amounts	**2018**	2017	2016
Oil, natural-gas, and NGL sales	**$ 11,482**	$ 8,969	$ 7,153
Gathering, processing, and marketing sales	**1,588**	2,000	1,294
Gains (losses) on divestitures and other, net	**312**	939	(578)
Revenues and other	**$ 13,382**	$ 11,908	$ 7,869
Costs and expenses	**10,763**	12,473	10,241
Other (income) expense	**1,134**	1,123	1,457
Income tax expense (benefit)	**733**	(1,477)	(1,021)
Net income (loss) attributable to common stockholders	**$ 615**	$ (456)	$ (3,071)
Net income (loss) per common share attributable to common stockholders—diluted	**$ 1.20**	$ (0.85)	$ (5.90)
Average number of common shares outstanding—diluted	**504**	548	522

The following discussion pertains to Anadarko's results of operations, financial condition, and changes in financial condition. Any increases or decreases "for the year ended December 31, 2018," refer to the comparison of the year ended December 31, 2018, to the year ended December 31, 2017. Similarly, any increases or decreases "for the year ended December 31, 2017," refer to the comparison of the year ended December 31, 2017, to the year ended December 31, 2016. The primary factors that affect the Company's results of operations include commodity prices for oil, natural gas, and NGLs; sales volume; the cost of finding and developing such reserves; and operating costs.

REVENUES AND SALES VOLUME



For 2018, the table below illustrates the effect of increases in commodity prices and changes associated with sales volume. Sales volume changes during 2018 included increases associated with continued drilling and completion activities in the Delaware and DJ basins and decreases associated with U.S. onshore asset divestitures in 2017 and 2018.



The following provides Anadarko's sales volume for the years ended December 31:

	Barrels of Oil Equivalent (MMBOE)			Barrels of Oil Equivalent per Day (MBOE/d)		
	2018	2017	2016	**2018**	2017	2016
United States	**208**	211	257	**570**	579	704
International	**35**	34	33	**96**	93	89
Total	**243**	245	290	**666**	672	793

Sales volume represents actual production volume adjusted for changes in commodity inventories as well as natural-gas production volume provided to satisfy a commitment under the Jubilee development plan in Ghana. Anadarko employs marketing strategies to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. For additional information, see *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. Production of oil, natural gas, and NGLs is usually not affected by seasonal swings in demand.

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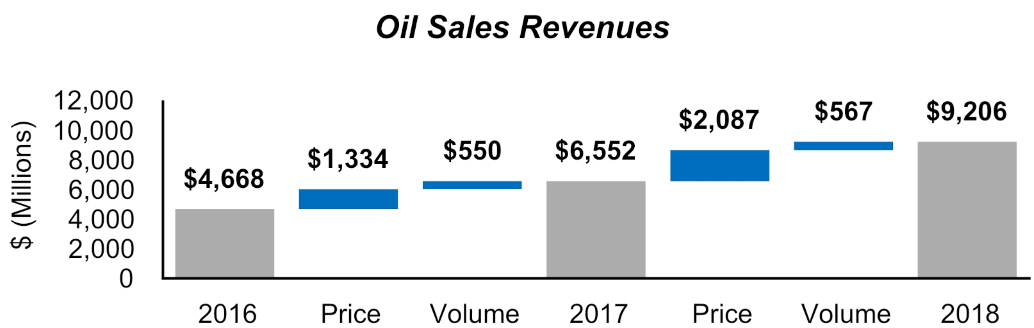
Oil Sales Revenues, Average Prices, and Volume



	2018	2017	2016
Oil sales revenues (millions)	$ 9,206	$ 6,552	$ 4,668
Price per barrel			
United States	$ 64.01	$ 49.62	$ 39.06
International	70.38	53.77	43.93
Total	$ 65.51	$ 50.66	$ 40.34
Sales volume (MMBbls)			
United States	108	97	85
International	33	32	31
Total	141	129	116
Sales volume per day (MBbls/d)			
United States	294	266	233
International	91	89	83
Total	385	355	316

Oil Prices

Anadarko's realized oil price increased in late 2016 through 2017, primarily due to the expectation of decreasing global oversupply as a result of OPEC's agreement to reduce production through the end of 2018. Oil prices continued to increase during most of 2018, primarily due to concerns of a supply shortfall as a result of reductions in output from Iran as the U.S. reimposed sanctions, as well as decreased production from Venezuela. Oil prices declined in the fourth quarter of 2018 due to concerns of oil demand weakness from a slowing global economy.

Oil Sales Volume

2018 vs. 2017 The Company's oil sales volume increased by 30 MBbls/d, primarily due to the following:

U.S. Onshore

- Sales volume for the Delaware basin increased by 27 MBbls/d, primarily due to continued drilling and completion activities and midstream infrastructure additions in 2018.
- Sales volume for the DJ basin increased by 14 MBbls/d, primarily due to continued drilling and completion activities in 2018.
- Divestitures resulted in decreased sales volume of 16 MBbls/d, primarily related to the sale of the Alaska nonoperated assets in the first quarter of 2018 and the Eagleford and West Chalk assets in the first half of 2017.

Gulf of Mexico

- Sales volume for the Gulf of Mexico remained flat, primarily due to natural production declines and planned downtime at various platforms, partially offset by new wells coming online at Horn Mountain, Holstein, Marlin, and Caesar Tonga throughout 2018.

2017 vs. 2016 The Company's oil sales volume increased by 39 MBbls/d, primarily due to the following:

U.S. Onshore

- Sales volume for the Delaware basin increased by 13 MBbls/d, primarily due to continued drilling and completion activities in 2017.
- Divestitures resulted in a decrease in sales volume of 29 MBbls/d, primarily related to the sale of the Eagleford assets in the first half of 2017.

Gulf of Mexico

- Sales volume increased by 56 MBbls/d, primarily due to the GOM Acquisition in December 2016 and continued tie-back activity at several facilities, partially offset by deferred production as a result of Hurricanes Harvey, Irma, and Nate and nonoperated field downtime during the second half of 2017.

International

- Sales volume for Ghana increased by 9 MBbls/d, primarily due to a full year of liftings from the TEN development, which came online late in the third quarter of 2016, and downtime in 2016 to address new production and offtake procedures resulting from issues associated with the Jubilee field FPSO turret bearing.

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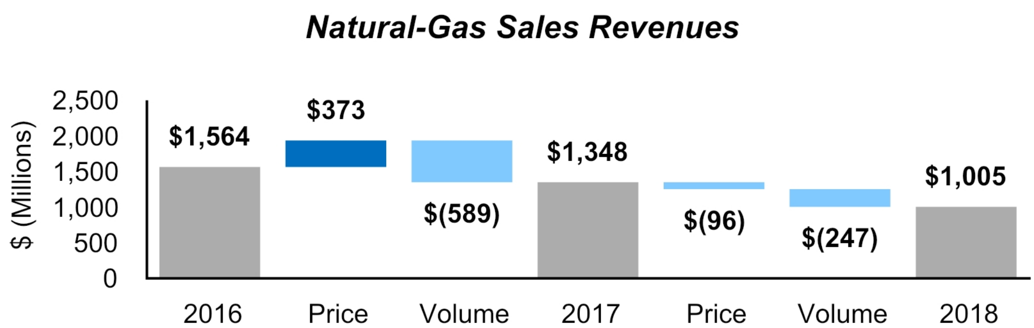
Natural-Gas Sales Revenues, Volume, and Average Prices



	2018	2017	2016
Natural-gas sales revenues (millions)	**$ 1,005**	$ 1,348	$ 1,564
Price per Mcf	**$ 2.57**	$ 2.82	$ 2.04
Sales volume (Bcf) [(1)]	**390**	478	766
Sales volume per day (MMcf/d) [(1)]	**1,069**	1,309	2,093

(1) All natural-gas sales volume originates in the United States.

Natural-Gas Prices

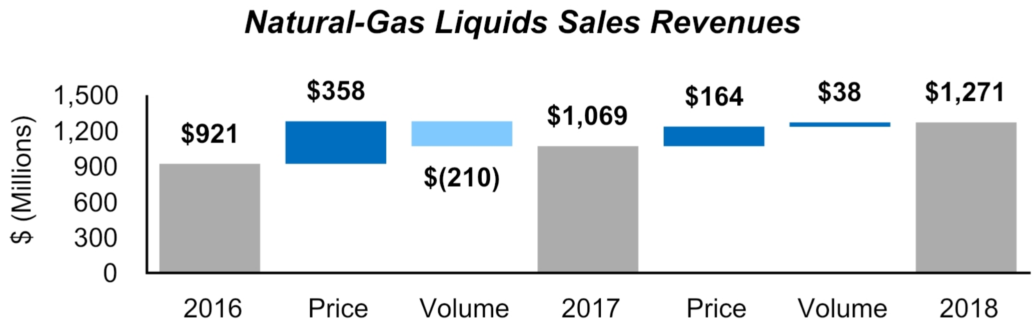
Anadarko's realized natural-gas price increased from 2016 to 2017, primarily due to a reduction of U.S. natural-gas storage resulting from production declines across the industry from mid-2016 through early 2017 and stable exports to Mexico throughout 2017. In 2018, NYMEX prices were higher due to strong demand growth and low U.S. natural-gas storage. However, Anadarko's realized natural-gas price decreased in 2018 due to wider regional differentials in its operated basins as strong production growth in the Delaware and DJ basins required higher utilization of gas pipeline takeaway capacity.

Natural-Gas Sales Volume

2018 vs. 2017 The Company's natural-gas sales volume decreased by 240 MMcf/d, primarily due to the sale of the Marcellus, Eagleford, and Utah CBM assets in the first half of 2017 and the Moxa assets in the second half of 2017.

2017 vs. 2016 The Company's natural-gas sales volume decreased by 784 MMcf/d, primarily due to the sale of the Marcellus and Eagleford assets in the first half of 2017, the Carthage and Elm Grove assets in the second half of 2016, and the Wamsutter assets in the first half of 2016.

Natural-Gas Liquids Sales Revenues, Volume, and Average Prices



	2018	2017	2016
Natural-gas liquids sales revenues (millions)	$ 1,271	$ 1,069	$ 921
Price per barrel	$ 33.93	$ 29.54	$ 19.64
Sales volume (MMBbls) [(1)]	37	36	46
Sales volume per day (MBbls/d) [(1)]	103	99	128

(1) Approximately 95% of NGL sales volume was from the United States.

NGL Prices

Anadarko's realized NGL price increased from 2016 to 2017, primarily due to increased domestic demand and higher exports. The average NGL price continued to increase during most of 2018, primarily due to increased demand for ethane to supply newly-constructed ethane cracker facilities. NGL prices declined in the fourth quarter of 2018 due to higher gas plant production of NGLs and loosening of infrastructure constraints.

NGL Sales Volume

2018 vs. 2017 The Company's NGL sales volume increased by 4 MBbls/d, primarily due to the following:

U.S. Onshore

- Sales volume for the Delaware basin increased by 9 MBbls/d, primarily due to continued drilling and completion activities and midstream infrastructure additions in 2018.
- Sales volume for other U.S. onshore assets decreased by 5 MBbls/d, primarily due to the sale of the Eagleford and West Chalk assets in the first half of 2017 and the Moxa assets in the second half of 2017.

2017 vs. 2016 The Company's NGL sales volume decreased by 29 MBbls/d, primarily due to the sale of the Eagleford assets in the first half of 2017 and the Carthage assets in the second half of 2016.

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Gathering, Processing, and Marketing

millions	**2018**	2017	2016
Gathering, processing, and marketing sales [(1)]	**$ 1,588**	$ 2,000	$ 1,294
Gathering, processing, and marketing expense [(1)]	**1,047**	1,552	1,083
Gathering, processing, and marketing, net	**$ 541**	$ 448	$ 211

(1) As a result of adopting ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, as of January 1, 2018, gathering, processing, and marketing sales decreased by $1.0 billion for the year ended December 31, 2018, and gathering, processing, and marketing expenses decreased by $1.0 billion for the year ended December 31, 2018. Refer to *Note 2—Revenue from Contracts with Customers* in the *Notes to Consolidated Financial Statements* under Part II, Item 8 of this Form 10-K for further information.

Gathering and processing sales include fee revenue earned by providing gathering, processing, compression, and treating services to third parties as well as revenue from the sale of NGLs and remaining residue gas extracted from natural gas purchased from third parties and processed by Anadarko. The net margin from the sale of NGLs and residue gas for service customers when Anadarko is acting as an agent is also included. Gathering and processing expense includes the cost of third-party natural gas purchased and processed by Anadarko as well as transportation and other operating expenses related to the Company's costs to perform gathering and processing activities for third parties.

Marketing sales include the margin earned from purchasing and selling third-party oil and natural gas. Marketing expense includes transportation and other operating expenses related to the Company's costs to perform third-party marketing activities.

2018 vs. 2017 Gathering, processing, and marketing, net increased by $93 million. This increase primarily related to higher third-party throughput volume at the West Texas Complex, which were partially due to increased capacity from the 200 MMcf/d cryogenic train that commenced service in December 2017, and increased third-party throughput volume and rates at the DJ Basin Complex. These increases were partially offset by decreased marketing margins related to pricing on NGL inventory.

2017 vs. 2016 Gathering, processing, and marketing, net increased by $237 million. This increase primarily related to higher third-party throughput volume and prices at the DBM Complex due to increased processing capacity from the start-up of newly constructed facilities in May and October 2016 and previously existing facilities returning to service after the 2016 outage at the DBM Complex.

Gains (Losses) on Divestitures and Other, net

millions	**2018**	2017	2016
Gains (losses) on divestitures, net	**$ 20**	$ 674	$ (757)
Other	**292**	265	179
Total gains (losses) on divestitures and other, net	**$ 312**	$ 939	$ (578)

Gains (losses) on divestitures and other, net includes gains (losses) on divestitures and other operating revenues, including earnings (losses) from equity investments, hard-minerals royalties, and other revenues.

During the years presented, Anadarko divested certain non-core U.S. onshore and Gulf of Mexico assets. See *Note 4—Divestitures and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

COSTS AND EXPENSES

The following provides Anadarko's total costs and expenses for the years ended December 31:

millions	2018	2017	2016
Oil and gas operating	$ 1,153	$ 988	$ 807
Oil and gas transportation	878	914	1,002
Exploration	459	2,535	944
Gathering, processing, and marketing	1,047	1,552	1,083
G&A	1,084	994	1,223
DD&A	4,254	4,279	4,301
Production, property, and other taxes	826	582	536
Impairments	800	408	227
Other operating expense	262	221	118
Total	$ 10,763	$ 12,473	$ 10,241

Oil and Gas Operating Expenses

	2018	2017	2016
Oil and gas operating (millions)	$ 1,153	$ 988	$ 807
Oil and gas operating—per BOE	4.74	4.03	2.78

2018 vs. 2017 Oil and gas operating expenses increased by $165 million, primarily due to the following:

- higher U.S. onshore costs of $140 million, primarily related to increased operating and nonoperating activity in the DJ and Delaware basins, partially offset by lower expenses of $74 million as a result of U.S. onshore asset divestitures
- higher non-operating costs of $54 million in Ghana, primarily due to the Jubilee FPSO turret repair and additional wells coming online in 2018
- higher operating costs of $32 million, primarily related to maintenance at various platforms in GOM

2017 vs. 2016 Oil and gas operating expenses increased by $181 million, primarily due to the following:

- higher operating costs of $212 million, primarily related to the GOM Acquisition
- higher operating costs of $84 million related to increased activity in the DJ and Delaware basins and costs related to the Company's response efforts in Colorado in 2017
- lower nonoperating costs of $12 million in Ghana, primarily related to FPSO maintenance costs in 2016, partially offset by higher costs in 2017 due to increased production from the TEN development, which came online late in the third quarter of 2016
- lower expenses of $89 million as a result of U.S. onshore asset divestitures

The related costs per BOE increased from 2016 to 2018, primarily due to increased costs as a result of shifting to a higher-return, oil-levered portfolio that includes the Gulf of Mexico and Delaware basin, which operate at a higher cost compared to the lower-return, gas-levered divested assets.

Oil and Gas Transportation Expenses

	2018	2017	2016
Oil and gas transportation (millions)	$ 878	$ 914	$ 1,002
Oil and gas transportation—per BOE	3.61	3.73	3.46

2018 vs. 2017 Oil and gas transportation expenses decreased by $36 million, primarily due to U.S. onshore divestitures and increased transportation costs related to sales from storage in 2017, partially offset by increased oil sales volume in the Delaware basin in 2018. Oil and gas transportation expenses per BOE remained relatively flat.

2017 vs. 2016 Oil and gas transportation expenses decreased by $88 million, primarily due to 2017 and 2016 U.S. onshore divestitures, partially offset by increased oil and gas sales volume in the Gulf of Mexico and increased rates in the DJ basin. Oil and gas transportation expenses per BOE increased by $0.27 primarily due to increased oil and natural-gas transportation rates in the DJ basin.

Exploration Expense

millions	2018	2017	2016
Dry hole expense	$ 87	$ 1,433	$ 397
Impairments of unproved properties	159	788	216
Geological and geophysical, exploration overhead, and other expense	213	314	331
Total exploration expense	$ 459	$ 2,535	$ 944

Dry Hole Expense

2018

– $87 million related to unsuccessful drilling activities, primarily in the Gulf of Mexico

2017

– $437 million related to the Shenandoah project, $215 million related to the Phobos project, and $108 million related to the Warrior project in the Gulf of Mexico due to insufficient quantities of oil pay to justify development
– $329 million related to all remaining wells in Côte d'Ivoire, where the Company relinquished its interest in all of its exploration blocks
– $243 million related to certain wells in the Grand Fuerte area in Colombia due to insufficient progress on contractual and fiscal reforms needed for deepwater natural-gas development

2016

– $231 million related to certain wells in the Gulf of Mexico and $92 million related to certain wells in Mozambique
– $39 million for a well in Côte d'Ivoire that finished drilling in the third quarter of 2016 and encountered noncommercial quantities of hydrocarbons

See *Note 7—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Impairments of Unproved Properties

For discussion related to impairments of unproved properties, see *Note 6—Impairments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-K.

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G&A

millions	2018	2017	2016
G&A	$ 1,084	$ 994	$ 1,223

2018 vs. 2017 G&A increased by $90 million, primarily due to an increase in employee-related expenses of $31 million, higher legal and consulting fees of $23 million and higher contract labor costs of $13 million.

2017 vs. 2016 G&A decreased by $229 million for the year ended December 31, 2017. Excluding $192 million of charges recorded in 2016 associated with the workforce reduction program, G&A remained relatively flat. See *Note 19—Restructuring Charges* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

DD&A

millions	2018	2017	2016
DD&A	$ 4,254	$ 4,279	$ 4,301

2018 vs. 2017 DD&A expense decreased by $25 million, primarily due to the following:

– $140 million decrease, primarily related to divestitures associated with U.S. onshore properties in 2018 and 2017 and a lower DD&A rate in 2018 driven by increased proved developed reserves in Ghana

These decreases were offset by the following:

– $62 million increase in ARO accretion expense due to increased ARO estimates in the Gulf of Mexico

– $53 million increase in straight line depreciation related to newly constructed pipelines and salt water disposal facilities in the Delaware basin

2017 vs. 2016 DD&A expense decreased by $22 million, primarily due to the following:

– $717 million related to lower 2017 sales volume and asset property balances associated with U.S. onshore properties as a result of divestitures in 2016 and 2017

These decreases were offset by the following:

– $457 million related to higher sales volume in the Gulf of Mexico, primarily due to the GOM Acquisition

– $240 million related to international production DD&A, primarily due to higher sales volume from the Ghana TEN project, which came online late in the third quarter of 2016

Production, Property, and Other Taxes

millions	2018	2017	2016
U.S. production and severance taxes	$ 164	$ 90	$ 80
Algeria exceptional profits taxes	405	289	280
Ad valorem taxes	254	196	163
Other	3	7	13
Total production, property, and other taxes	$ 826	$ 582	$ 536

2018 vs. 2017 Production, property and other taxes increased by $244 million, primarily due to an increase in ad valorem and U.S. production and severance taxes driven by higher sales volume and commodity prices in the Delaware and DJ basins. Additionally, Algeria exceptional profits taxes increased due to higher commodity prices.

2017 vs. 2016 Production, property and other taxes increased by $46 million, primarily due to an increase in commodity prices.

Impairments

The Company recognized the following impairments for the years ended December 31:

millions		2018		2017		2016
Exploration and Production						
U.S. onshore properties	$	347	$	2	$	28
Gulf of Mexico properties		27		227		27
Cost-method investment		—		—		59
WES Midstream		228		176		16
Other Midstream		53		2		57
Other		145		1		40
Total impairments	$	800	$	408	$	227

See Note 6—Impairments in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on impairments and Risk Factors under Item 1A of this Form 10-K for further discussion on the risks associated with oil, natural-gas, and NGL prices.

Other (Income) Expense

The following provides Anadarko's other (income) expense for the years ended December 31:

millions		2018		2017		2016
Interest expense (1)	$	947	$	932	$	890
(Gains) losses on early extinguishment of debt (2)		(2)		2		155
(Gains) losses on derivatives, net (3)		130		135		286
Other (income) expense, net		59		54		126
Total	$	1,134	$	1,123	$	1,457

(1) Interest expense increased from 2016 to 2017 primarily due to lower capitalized interest in 2017. See Note 13—Debt and Interest Expense in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.
(2) See Financing Activities in *Liquidity and Capital Resources* for additional information.
(3) See Note 11—Derivative Instruments in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Income Tax Expense (Benefit)

Total income taxes differed from the amounts computed by applying the U.S. federal statutory income tax rate to income (loss) before income taxes. The following summarizes the sources of these differences for the years ended December 31:

millions except percentages	2018	2017	2016
Income tax expense (benefit)	$ 733	$ (1,477)	$ (1,021)
Income (loss) before income taxes	$ 1,485	$ (1,688)	$ (3,829)
Effective tax rate	49%	88%	27%

In 2017, as a result of the Tax Reform Legislation, the Company recognized a one-time deferred tax benefit of $1.2 billion primarily due to the remeasurement of its U.S. deferred tax assets and liabilities, resulting in an 88% effective tax rate. Excluding this one-time benefit, the Company's effective tax rate would have been 18%. The Company remeasured its U.S. deferred tax assets and liabilities based on the reduction of the U.S. corporate tax rate from 35% to 21%. After completing the accounting for income tax effects related to the adoption of the Tax Reform Legislation in 2018, the Company revised the provisional amount and recognized an additional current tax benefit of $26 million offset by deferred tax expense of $121 million. Excluding the impact from the Tax Reform Legislation, the Company's 2018 effective tax rate would have been 43%.

The Company's effective tax rate is impacted each year by the relative pre-tax income (loss) earned by the Company's operations in the U.S., Algeria, and the rest of the world. The Company is subject to statutory tax rates of 38% in Algeria and 35% in Ghana. These higher-taxed foreign operations as well as non-deductible Algerian exceptional profits tax for Algerian income tax purposes generally cause the Company's effective tax rate to vary significantly from the U.S. corporate tax rate. Additionally, the Company's effective tax rate is typically impacted by net changes in uncertain tax positions, income attributable to noncontrolling interests, state income taxes (net of federal benefit), and dispositions of non-deductible goodwill. Excluding the impact related to the Tax Reform Legislation in 2017 and 2018, the Company's effective tax rate increased from 18% in 2017 to 43% in 2018 primarily due to higher-taxed income earned in Algeria relative to the Company's pretax income in the United States. The Company's effective tax rate decreased from 27% in 2016 to 18% in 2017, primarily due to the higher-taxed income earned in Algeria relative to the Company's pretax losses in the U.S. and Ghana as well as the impact of international exploration pretax losses with no associated tax benefit.

The Company received an $881 million tentative refund in 2016 related to its $5.2 billion Tronox settlement payment in 2015. In April 2018, the IRS issued a final notice of proposed adjustment denying the deductibility of the settlement payment. In September 2018, the Company received a statutory notice of deficiency from the IRS disallowing the net operating loss carryback and rejecting the Company's refund claim. As a result, the Company filed a petition with the U.S. Tax Court to dispute the disallowances in November 2018, and pursuant to standard U.S. Tax Court procedures, is not required to repay the $881 million refund to dispute the IRS's position. Accordingly, the Company has not revised its estimate of the benefit that will ultimately be realized. After the case is tried and briefed in the Tax Court, the court will issue an opinion and then enter a decision. If the Company does not prevail on the issue, the earliest potential date the Company might be required to repay the refund received, plus interest, would be 91 days after entry of the decision. At such time, the Company would reverse the portion of the $346 million net benefit previously recognized in its consolidated financial statements to the extent necessary to reflect the result of the Tax Court decision. It is reasonably possible the amount of uncertain tax position and/or tax benefit could materially change as the Company asserts its position in the Tax Court proceedings. Although management cannot predict the timing of a final resolution of the Tax Court proceedings, the Company does not anticipate a decision to be entered within the next three years.

For additional information on income taxes, see *Note 14—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

LIQUIDITY AND CAPITAL RESOURCES

millions	**2018**	2017	2016
Net cash provided by (used in) operating activities	**$ 5,929**	$ 4,009	$ 3,000
Net cash provided by (used in) investing activities	**(5,982)**	(1,030)	(2,742)
Net cash provided by (used in) financing activities	**(3,177)**	(1,613)	2,008

Overview

The Company has a variety of funding sources available, including cash, an asset portfolio that provides ongoing cash-flow-generating capacity, opportunities for liquidity enhancement through asset divestitures and joint-venture arrangements that reduce future capital expenditures, the Company's credit facility, and access to both debt and equity capital markets. In addition, an effective registration statement is available to Anadarko covering the sale of WGP common units owned by the Company. WGP and WES function with capital structures that are separate from Anadarko, consisting of their own debt instruments and publicly traded common units.

During 2018, Anadarko repurchased $2.7 billion of shares under the Share-Repurchase Program, retired more than $600 million of debt, and received net proceeds of $417 million from divestitures, primarily related to the sale of the Company's nonoperated interests in Alaska. Anadarko had $1.3 billion of cash at December 31, 2018. Following the expiration of the 364-Day Facility in January 2019, the Company has $3.0 billion of borrowing capacity under the APC RCF. Anadarko believes that its current available cash, anticipated proceeds from the sale of midstream assets to WES, and future operating cash flows will be sufficient to fund the Company's projected long-term operational and capital programs, fund the increased dividends, and complete both the Share-Repurchase Program and the debt-reduction program. The Company continuously monitors its liquidity position and evaluates available funding alternatives in light of current and expected conditions.

In order to reduce commodity-price risk and increase the predictability of 2019 cash flows, the Company entered into strategic derivative positions covering approximately 21% of its anticipated oil sales volume for 2019. The Company entered into three-way collars for 87 MBbls/d, consisting of a sold call at $72.98, a purchased put at $56.72, and a sold put at $46.72. See *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Credit Rating

As of December 31, 2018, the Company's long-term debt was rated investment grade (BBB) by both S&P and Fitch and below investment grade (Ba1) by Moody's. Subsequent to year end, Moody's changed its outlook with respect to its rating from stable to positive. As a result of Moody's Ba1 rating, Anadarko is more likely to be required to post collateral in the form of letters of credit or cash under certain contractual arrangements, such as derivative instruments, pipeline transportation contracts, and oil and gas sales contracts. Collateral related to credit-risk-related contingent features for which a net liability position existed was $66 million at December 31, 2018, and $170 million at December 31, 2017. For more information on credit-risk considerations, see *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. The amount of letters of credit or cash provided as assurance of the Company's performance under pipeline transportation contracts and oil and gas sales contracts with respect to credit-risk-related contingent features was $260 million at December 31, 2018, and $263 million at December 31, 2017.

Operating Activities

One of the primary sources of variability in the Company's cash flows from operating activities is the fluctuation in commodity prices, the impact of which Anadarko partially mitigates by periodically entering into commodity derivatives. Sales-volume changes also impact cash flow but historically have not been as volatile as commodity prices. Anadarko's cash flows from operating activities are also impacted by the costs related to operations and interest payments related to the Company's outstanding debt.

Cash flows from operating activities were $5.9 billion for 2018, $1.9 billion higher compared to 2017, primarily due to higher sales revenues resulting from higher oil prices.

Cash flows from operating activities were $4.0 billion for 2017, $1.0 billion higher compared to 2016, primarily due to higher sales revenues resulting from higher commodity prices. Additional significant items impacting operating activities for 2016 were the $159.5 million payment of the Clean Water Act (CWA) penalty, $247 million related to severance costs and retirement benefits paid in connection with the workforce reduction program, and the receipt of an $881 million tax refund related to the income tax benefit associated with the Company's 2015 tax net operating loss carryback.

See *Note 14—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion related to the potential repayment of the 2016 tax refund.

Pension and Other Postretirement Contributions Contributions to the pension and other postretirement plans were $244 million in 2018, $276 million in 2017, and $120 million in 2016. The Company expects to contribute $155 million in 2019 to its pension and other postretirement plans.

Investing Activities

Capital Expenditures The following presents the Company's capital expenditures:

millions	2018	2017	2016
Cash Flows from Investing Activities			
Additions to properties and equipment [(1)]	$ 6,183	$ 5,031	$ 3,505
Adjustments for capital expenditures			
Changes in capital accruals	(3)	275	(205)
Other	5	(6)	14
Total capital expenditures [(2)]	$ 6,185	$ 5,300	$ 3,314
Exploration and Production and other capital expenditures	$ 4,264	$ 3,884	$ 2,763
WES Midstream capital expenditures	1,178	956	491
Other Midstream capital expenditures	743	460	60

(1) Additions to properties and equipment as presented within Anadarko's cash flows from investing activities include cash payments for cost of properties, equipment, and facilities. The cost of properties includes the initial capitalization of drilling costs associated with all exploratory wells, whether or not they were deemed to have a commercially sufficient quantity of proved reserves.

(2) Capital expenditures exclude the FPSO capital lease asset; see Financing Activities—*Capital Lease Obligations* below.

2018 vs. 2017 The Company's capital expenditures increased by $885 million for the year ended December 31, 2018. Exploration and Production capital expenditures increased primarily due to higher development costs of $809 million driven by increased drilling and completion activities primarily in the DJ and Delaware basins and the Gulf of Mexico. Exploration costs decreased by $485 million primarily related to decreased exploration drilling in the Gulf of Mexico, Côte d'Ivoire, and Colombia. Other Midstream capital expenditures increased $283 million due to infrastructure build-out primarily in the Delaware basin. WES Midstream capital expenditures increased $222 million primarily related to infrastructure build-out in the Delaware and DJ basins.

2017 vs. 2016 The Company's capital expenditures increased by $2.0 billion for the year ended December 31, 2017. Exploration and Production capital expenditures increased primarily due to higher development costs of $925 million driven by increased U.S. onshore drilling activity primarily in the DJ basin and operatorship capture in the Delaware basin as well as higher exploration costs of $356 million primarily driven by U.S. onshore acreage acquisitions and $172 million primarily due to exploration drilling in the Gulf of Mexico. These increases were partially offset by decreased development costs of $227 million driven by the TEN development in Ghana, which achieved first oil in the third quarter of 2016. WES Midstream capital expenditures increased primarily due to $465 million related to the development of assets primarily in the Delaware and DJ basins. Other Midstream capital expenditures increased $400 million due to asset development primarily in the Delaware basin.

Property Exchange On March 17, 2017, WES acquired a third party's 50% nonoperated interest in the DBJV System, now part of the West Texas Complex, in exchange for WES's 33.75% interest in nonoperated Marcellus midstream assets and $155 million in cash. WES funded the cash consideration with cash on hand and recognized a gain of $126 million as a result of this transaction. After the acquisition, the DBJV System was 100% owned by WES and consolidated by Anadarko. See *Note 4—Divestitures and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Acquisitions In December 2016, the Company closed the GOM Acquisition for $1.8 billion.

Investments The Company made capital contributions for equity investments of $303 million in 2018, $29 million in 2017, and $62 million in 2016, which are presented as cash flows from investing activities as a component of Other, net. These contributions were primarily associated with joint ventures for the Midland-to-Sealy and Cactus II pipelines in West Texas in 2018, the Ranch Westex natural-gas processing plant in West Texas in 2017, and the Saddlehorn-Grand Mesa pipeline in Colorado in 2016.

Divestitures Anadarko received net proceeds from property divestitures of $417 million in 2018, $4.0 billion in 2017, and $2.4 billion in 2016. See *Note 4—Divestitures and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Financing Activities

	December 31,	
millions except percentages	**2018**	2017
Anadarko	**$ 11,602**	$ 12,196
WES	**4,787**	3,465
WGP	**28**	28
Total debt	**$ 16,417**	$ 15,689
Total equity	**10,943**	13,790
Consolidated debt to total capitalization ratio	**60.0%**	53.2%

Debt-reduction Program The Company has commenced a $2.0 billion debt-reduction program. As of December 31, 2018, Anadarko had retired more than $600 million of debt and plans to repay $900 million of debt maturing in the first half of 2019. An additional $500 million of debt reduction is anticipated through mid-year 2020.

Credit Facilities

APC RCFs The Company has a $3.0 billion senior unsecured RCF that matures in January 2023. The Company's $2.0 billion 364-day senior unsecured RCF expired in January 2019. At December 31, 2018, Anadarko had no outstanding borrowings under the APC RCF or the 364-Day Facility and was in compliance with all covenants.

WES RCF WES has a $1.5 billion senior unsecured RCF which is expandable to a maximum of $2.0 billion that matures in February 2023. At December 31, 2018, WES had outstanding borrowings under its RCF of $220 million, outstanding letters of credit of $5 million, available borrowing capacity of $1.3 billion, and was in compliance with all covenants.

In December 2018, WES entered into an amendment to extend the maturity date of the WES RCF from February 2023 to February 2024 effective on February 15, 2019 and to expand the borrowing capacity to $2.0 billion, while leaving the $500 million accordion feature unexercised. Expansion of the borrowing capacity is subject to the completion of the WES Merger anticipated in the first quarter of 2019. See *Note 24—Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information related to the WES Merger.

WGP RCF WGP has a $35 million senior secured RCF that matures the earlier of June 2019 or three business days following the completion of the WES Merger. At December 31, 2018, WGP had outstanding borrowings under its RCF of $28 million classified as short-term debt on the Company's Consolidated Balance Sheet, available borrowing capacity of $7 million, and was in compliance with all covenants. See *Note 24—Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information related to the WES Merger.

Commercial Paper Program The Company has a commercial paper program, which allows for a maximum of $3.0 billion of unsecured commercial paper notes. As a result of Moody's credit rating on Anadarko, the Company's access to the commercial paper market has been limited. There were no outstanding borrowings under the commercial paper program at December 31, 2018.

Debt Activity Amounts in the table below do not include capital lease activity and are presented at face value.

millions	Company	2018	2017	2016	Description
Issuances	Anadarko	$ —	$ —	$ 800	4.850% Senior Notes due 2021 (1)
	Anadarko	—	—	1,100	5.550% Senior Notes due 2026 (1)
	Anadarko	—	—	1,100	6.600% Senior Notes due 2046 (1)
	WES	400	—	—	WES 4.500% Senior Notes due 2028 (2)
	WES	700	—	—	WES 5.300% Senior Notes due 2048 (2)
	WES	400	—	—	WES 4.750% Senior Notes due 2028 (3)
	WES	350	—	—	WES 5.500% Senior Notes due 2048 (3)
	WES	—	—	500	WES 4.650% Senior Notes due 2026 (4)
	WES	—	—	200	WES 5.450% Senior Notes due 2044 (2)
Borrowings	Anadarko	—	—	1,750	364-Day Facility (5)
	WES	540	370	600	WES RCF (6)
	WGP	—	—	28	WGP RCF
Repayments	Anadarko	(114)	—	—	7.050% Debentures due 2018
	Anadarko	(123)	—	—	4.850% Senior Notes due 2021 (7)
	Anadarko	(377)	—	—	3.450% Senior Notes due 2024 (7)
	Anadarko	(90)	—	—	Zero Coupon Notes due 2036
	Anadarko	—	(6)	—	7.000% Debentures due 2027
	Anadarko	—	(3)	—	6.625% Debentures due 2028
	Anadarko	—	(1)	—	7.950% Debentures due 2029
	Anadarko	—	—	(1,750)	5.950% Senior Notes due 2016 (8)
	Anadarko	—	—	(2,000)	6.375% Senior Notes due 2017 (8)
	Anadarko	—	—	(1,750)	364-Day Facility
	Anadarko	—	—	(250)	Commercial paper notes, net
	Anadarko	(17)	(34)	(34)	TEUs - senior amortizing notes
	WES	(350)	—	—	WES 2.600% Senior Notes due 2018
	WES	(690)	—	(900)	WES RCF

(1) Proceeds were used to purchase and retire $1.250 billion of its $2.0 billion 6.375% Senior Notes due September 2017 pursuant to a tender offer and to redeem its $1.750 billion 5.950% Senior Notes due September 2016.

(2) Proceeds were used to repay amounts outstanding under the WES RCF, with remaining proceeds used for general partnership purposes, including capital expenditures.

(3) Proceeds were used to repay the maturing $350 million 2.600% Senior Notes due August 2018 and amounts outstanding under the WES RCF, with remaining proceeds used for general partnership purposes, including capital expenditures.

(4) Proceeds were used to repay a portion of the amount outstanding under the WES RCF.

(5) Proceeds were primarily used for general short-term working capital needs.

(6) Borrowings in 2018 and 2017 were used for general partnership purposes, including capital expenditures. In 2016, borrowings were used to fund a portion of an acquisition and for general partnership purposes, including capital expenditures.

(7) The Company purchased and retired $377 million of its $625 million 3.450% Senior Notes due 2024 and $123 million of its $800 million 4.850% Senior Notes due 2021 pursuant to a tender offer.

(8) The Company recognized losses of $155 million for the early retirement and redemption of these senior notes, which included $144 million of premiums paid.

See Note 13—Debt and Interest Expense in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Debt Maturities At December 31, 2018, Anadarko had outstanding borrowings of $600 million of 8.700% Senior Notes due March 2019 and $300 million of 6.950% Senior Notes due June 2019 classified as short-term debt on the Company's Consolidated Balance Sheet. The Company plans to retire this debt at maturity.

In December 2018, the Company purchased and retired $36 million of the accreted value of its Zero Coupons due 2036, which resulted in a reduction of $90 million of the $2.4 billion originally due at maturity in 2036. The principal payments related to the Zero Coupons are reported in financing activities and interest accretion payments related to the Zero Coupons are reported in operating activities on the Company's Consolidated Statement of Cash Flows. Anadarko's Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value of the outstanding Zero Coupons. None of the Zero Coupons were put to the Company in October 2018. The Zero Coupons can next be put to the Company in October 2019, which, if put in whole, would be $942 million. Anadarko's Zero Coupons were classified as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2018, as the Company has the ability and intent to refinance these obligations using long-term debt, should a put be exercised.

For additional information on the Company's debt instruments, such as transactions during the period, years of maturity, and interest rates, see Note 13—Debt and Interest Expense in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Capital Lease Obligations Construction of the FPSO for the Company's TEN field operations in Ghana commenced in 2013. The Company recognized an asset and related obligation during the construction period for its pro-rata share. Upon completion of the construction during the third quarter of 2016, the Company reported the asset and related obligation as a capital lease of $225 million for the Company's share of the fair value of the FPSO based on the operator's lease agreement. The Company made capital lease payments of $46 million in 2018 and $44 million in 2017. Anadarko's scheduled payments for 2019 associated with capital lease obligations are $58 million. Principal payments related to capital lease obligations are reported in financing activities and interest payments related to capital lease obligations are reported in operating activities on the Company's Consolidated Statement of Cash Flows. See Note 13—Debt and Interest Expense in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Equity Transactions During 2018, as part of the Share-Repurchase Program, the Company completed the repurchase of 43.1 million shares of its common stock for $2.7 billion under two ASR Agreements and through open-market repurchases. During 2017, the Company completed the repurchase of 21.9 million shares of its common stock for $1.1 billion under an ASR Agreement and through open-market repurchases. For additional information, see Note 21—Stockholders' Equity in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

In September 2016, Anadarko completed a public offering of 40.5 million shares of its common stock for net proceeds of $2.16 billion. Net proceeds were primarily used to fund the GOM Acquisition, with the remainder used for general corporate purposes.

Anadarko sold 12.5 million of its WGP common units to the public for net proceeds of $476 million in 2016. The proceeds were used for general corporate purposes. At December 31, 2018, Anadarko owned 170 million WGP common units, which represents a 77.8% interest in WGP.

During 2016, WES issued 22 million Series A Preferred units to private investors for net proceeds of $687 million.

Derivative Instruments Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio is subject to changes in interest rates. Net cash payments related to settlements and amendments of interest-rate swap agreements were $92 million in 2018, $112 million in 2017, and $274 million in 2016. For information on derivative instruments, including cash flow treatment, see Note 11—Derivative Instruments in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Conveyance of Future Hard-Minerals Royalty Revenues During the first quarter of 2016, the Company conveyed a limited-term nonparticipating royalty interest in certain of its coal and trona leases to a third party for $413 million, net of transaction costs. The Company made payments for royalties of $50 million in both 2018 and 2017, and $25 million in 2016. For additional information on the cash flow treatment, expected timing, and scheduled payments of the conveyed royalties, see Note 16—Conveyance of Future Hard-Minerals Royalty Revenues in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Common Stock Dividends Anadarko paid dividends to its common stockholders of $528 million in 2018, $111 million in 2017, and $105 million in 2016. In response to a sustained decline in commodity prices, the Company decreased the quarterly dividend from $0.27 per share to $0.05 per share in February 2016. In February 2018, the Company increased the quarterly dividend to $0.25 per share. As part of the Company's focus on increasing shareholder returns, the quarterly dividend was increased again in November 2018 to $0.30 per share. Anadarko has paid a dividend to its common stockholders quarterly since becoming a public company in 1986.

The amount of future dividends paid to Anadarko common stockholders is determined by the Board on a quarterly basis and is based on the Company's earnings, financial condition, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors deemed relevant by the Board.

Distributions to Noncontrolling Interest Owners Distributions to noncontrolling interest owners primarily relate to the following:

millions	2018	2017	2016
WES distributions to unitholders (excluding Anadarko and WGP) (1)	$ 379	$ 326	$ 258
WES distributions to Series A Preferred unitholders (2)	—	22	31
WES distributions to Chipeta noncontrolling interest owners	14	14	14
WGP distributions to unitholders (excluding Anadarko) (3)	102	81	59

(1) WES has made quarterly distributions to its unitholders since its IPO in the second quarter of 2008 and has increased its distribution from $0.30 per common unit for the third quarter of 2008 to $0.98 per common unit for the fourth quarter of 2018 (paid in February 2019).

(2) WES made distributions of $0.68 per unit, prorated based on issuance date, to its Series A Preferred unitholders since the unit issuances in March and April 2016. As of June 30, 2017, all Series A Preferred units had converted into WES common units. See *Note 24—Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(3) WGP has made quarterly distributions to its unitholders since its IPO in December 2012 and has increased its distribution from $0.17875 per common unit for the first quarter of 2013 to $0.6025 per unit for the fourth quarter of 2018 (to be paid in February 2019).

Insurance Coverage and Other Indemnities

Anadarko maintains property and casualty insurance that includes coverage for physical damage to the Company's properties, blowout/control of a well, restoration and redrill, sudden and accidental pollution, third-party liability, workers' compensation and employers' liability, and other risks. Anadarko's insurance coverage includes deductibles that must be met prior to recovery. Additionally, the Company's insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect the Company against liability or loss from all potential consequences and damages.

The Company's current insurance coverage includes (a) $400 million per occurrence from Oil Insurance Limited (OIL) for physical damage to Anadarko's properties on a replacement cost basis, blowout/control of well, restoration and redrill, and sudden and accidental pollution; (b) $1.2 billion per occurrence from the commercial markets for the items described in item (a) above, which is in excess of the OIL coverage and which follows the form of OIL coverage with certain exceptions; (c) $500 million from the commercial markets, which scales to Anadarko's working interest, for third-party liabilities, including sudden and accidental pollution and aviation liability; and (d) $275 million for aircraft liability (in addition to the third-party liability limits described in item (c) above). Anadarko does not carry significant coverage for loss of production income from any of the Company's facilities or for any losses that result from the effects of a named windstorm.

The Company's service agreements, including drilling contracts, generally indemnify Anadarko for injuries and death to employees of the service provider and subcontractors hired by the service provider as well as for property damage suffered by the service provider and its contractors. Also, these service agreements generally indemnify Anadarko for pollution originating from the equipment of any contractors or subcontractors hired by the service provider.

Off-Balance-Sheet Arrangements

Anadarko may enter into off-balance-sheet arrangements and transactions that can give rise to material off-balance-sheet obligations. The Company's material off-balance-sheet arrangements and transactions include operating lease arrangements and undrawn letters of credit. In addition, the Company enters into other contractual agreements in the normal course of business for processing, treating, transportation, and storage of oil, natural gas, and NGLs, as well as for other oil and gas activities as discussed below in *Obligations*. Other than the items discussed above, there are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Anadarko's liquidity or availability of, or requirements for, capital resources.

Obligations

The following is a summary of the Company's obligations at December 31, 2018:

		Obligations by Period				
millions	Note Reference [1]	2019	2020-2021	2022-2023	Thereafter	Total
Total debt						
Principal—total borrowings [2]	Note 13	$ 928	$ 1,177	$ 890	$ 14,666	$ 17,661
Interest on borrowings	Note 13	834	1,655	1,530	9,515	13,534
Capital lease obligation and interest	Note 13	58	98	88	323	567
Investee entities' debt and interest [3]	Note 9	108	206	204	2,115	2,633
Operating leases	Note 17	264	196	59	135	654
Oil and gas activities [4]	Note 17	272	332	109	89	802
Midstream and marketing activities	Note 17	875	1,816	1,323	1,409	5,423
AROs	Note 15	254	345	699	1,801	3,099
Derivative liabilities [5]	Note 11	72	655	448	—	1,175
Uncertain tax positions [6]	Note 14	70	74	1,143	—	1,287
Environmental liabilities	Note 18	22	35	10	42	109
Other		20	200	31	57	308
Total [7]		$ 3,777	$ 6,789	$ 6,534	$ 30,152	$ 47,252

(1) For additional information, see the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.
(2) Includes the fully accreted principal amount of the Zero Coupons of approximately $2.3 billion as coming due after 2023. While the Zero Coupons do not mature until 2036, the outstanding Zero Coupons can be put to the Company each October, in whole or in part, for the then-accreted value. The Company could be required to repurchase the outstanding Zero Coupons for $942 million, if put in whole, in October 2019 (the next potential put date).
(3) The obligations and related investments are presented net on the Company's Consolidated Balance Sheets in other assets or other long-term liabilities-other. Future interest payments are estimated using the relevant forward LIBOR rate curve. The preferred return that Anadarko receives on its investment in these entities is not included.
(4) Includes long-term drilling and work-related commitments of $802 million, comprised of approximately $670 million related to the United States and $132 million related to international locations. Amounts are undiscounted and do not include purchase commitments for jointly owned fields and facilities where the Company is not the operator.
(5) Represents Anadarko's gross derivative liability after taking into account the impacts of netting margin and collateral balances deposited with counterparties.
(6) Timing of conclusion of the uncertain tax positions cannot be determined with certainty.
(7) Excludes litigation-related contingent liabilities, the Company's pension and postretirement benefit obligations, or payments related to the conveyance of future hard-minerals royalty revenues. See *Note 18—Contingencies*, *Note 20—Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans*, and *Note 16—Conveyance of Future Hard-Minerals Royalty Revenues* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of the Company's significant accounting policies. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment. The selection, development, and disclosure of these estimates is discussed with the Company's Audit Committee.

Proved Reserves

Methodology Anadarko estimates its proved oil and gas reserves according to the definition of proved reserves provided by the SEC and the FASB. This definition includes oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, government regulations, etc. (at prices and costs as of the date the estimates are made). Prices include consideration of price changes provided only by contractual arrangements, and do not include adjustments based on expected future conditions. For reserves information, see *Oil and Gas Properties and Activities—Proved Reserves* under Items 1 and 2 of this Form 10-K and the *Supplemental Information on Oil and Gas Exploration and Production Activities* under Item 8 of this Form 10-K.

Judgments and uncertainties Engineering estimates of the quantities of proved reserves are inherently imprecise and represent only approximate amounts because of the judgments involved in developing such information. The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, development plans, reservoir performance, prices, economic conditions, and governmental restrictions as well as changes in the expected recovery associated with infill drilling. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits at an earlier projected date.

A material adverse change in the estimated volume of proved reserves could have a negative impact on DD&A and could result in property impairments. If the estimates of proved reserves used in the UOP calculations had been lower by 10% across all properties, DD&A in 2018 would have increased by approximately $390 million.

Exploratory Costs

Methodology Under the successful efforts method of accounting, exploratory drilling costs are initially capitalized pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities, in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, analyzing whether development negotiations are underway and proceeding as planned.

Judgments and uncertainties Significant management judgment is required to determine whether sufficient progress has been made in assessing the reserves and the economic and operating viability of the project to continue capitalization of the exploratory drilling costs. In making this determination all relevant facts and circumstances shall be evaluated, and no single indicator is determinative. Relevant facts and circumstances include, but are not limited to, commitment of project personnel, costs being incurred to assess the reserves and their potential development, assessment in progress covering the economic, legal, political, and environmental aspects of the potential development, and the existence or active negotiations of agreements with governments or sales contracts with customers. The determination of proved reserves may take longer than one year in certain areas (generally in deepwater and international locations) depending on, among other things, the amount of hydrocarbons discovered, the outcome of planned geological and engineering studies, the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan, and government sanctioning of development activities in certain international locations.

If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. Therefore, at any point in time, the Company may have capitalized costs on its Consolidated Balance Sheets associated with exploratory wells that may be charged to exploration expense in future periods. See *Note 7—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Fair Value

Methodology The Company estimates fair value of long-lived assets for impairment testing, reporting units for goodwill impairment testing when necessary, assets and liabilities acquired in a business combination or exchanged in non-monetary transactions, pension plan assets, and initial measurements of AROs.

Judgments and uncertainties When the Company is required to measure fair value and there is not a market-observable price for the asset or liability or for a similar asset or liability, the Company uses the cost or income approaches depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of future net cash flows and discounts the expected cash flows using a commensurate risk-adjusted discount rate. Such evaluations involve significant judgment, and the results are based on expected future events or conditions such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, economic and regulatory climates, and other factors, most of which are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs, and other factors and are consistent with assumptions used in the Company's business plans and investment decisions.

Impairments of Proved Oil and Natural-Gas Properties

Methodology Proved oil and natural-gas properties are assessed for impairment when facts and circumstances indicate that net book values may not be recoverable. When impairment indicators are present, an undiscounted future net cash flow test is performed at the lowest level for which identifiable cash flows are independent of cash flows from other assets. If the sum of the undiscounted future net cash flows is less than the net book value of the property, the property's fair value is estimated and an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value.

Judgments and uncertainties The primary assumptions used to estimate undiscounted future net cash flows include anticipated future production, commodity prices, and capital and operating costs. In most cases, the assumption that generates the most variability in undiscounted future net cash flows is future commodity prices. For impairment testing, the Company used the five-year forward strip prices for oil and natural gas, with prices subsequent to the fifth year held constant as the benchmark price in the undiscounted future net cash flows. Capital and operating costs were estimated assuming no escalation for years where the average oil strip price was below $50 per Bbl and 1% escalation for the years where the average oil strip price exceeded $50 per Bbl and held constant thereafter.

Due to the volatility of crude oil, natural gas, and NGL prices, these cash flow estimates are inherently imprecise. Unfavorable changes in any of the primary assumptions could result in a reduction in undiscounted future cash flows and could indicate property impairment. Uncertainties related to the primary assumptions could affect the timing of an impairment.

Impairments of Unproved Oil and Natural-Gas Properties

Methodology Acquisition costs of unproved oil and natural-gas properties are periodically assessed for impairment and are transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. The Company has classified unproved oil and natural-gas properties into three categories: significant, significant where probable and possible reserves estimations are available, and individually insignificant. Significant undeveloped leases are assessed individually for impairment and a valuation allowance is provided if impairment is indicated. In situations where fair values have been allocated to a significant unproved property based on estimations of probable and possible reserves as the result of a business combination or other purchase of proved and unproved properties, an undiscounted future net cash flow analysis is used to assess the property for impairment in addition to consideration of reserves volume needed to transfer the balance of unproved property to proved property. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis (thereby establishing a valuation allowance) over the average lease terms at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment.

Judgments and uncertainties In determining whether a significant unproved property is impaired numerous factors are considered including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, geologists' evaluation of the property, and the remaining months in the lease term for the property. In situations where probable and possible reserves are available, undiscounted future net cash flows used in the impairment analysis are determined based upon management's estimates of probable and possible reserves, future commodity prices, and future costs to produce the reserves. If undiscounted future net cash flows are less than the carrying value of the property, indicating impairment, the future net cash flows are discounted and compared to the carrying value for determining the amount of the impairment loss to record. The Company utilizes the same pricing and cost assumptions discussed above in Impairments of Proved Oil and Natural-Gas Properties. Uncertainties related to the primary assumptions or unfavorable revisions in estimated reserves quantities could cause a reduction in the value of a property and therefore indicate an impairment. Management's assessment of the results of exploration activities, availability of funds for future activities, and the current and projected political and regulatory climate in areas in which the Company operates also impact the amounts and timing of impairment provisions.

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Income Taxes

Methodology The Company is subject to income taxes in numerous taxing jurisdictions worldwide. The amount of income taxes recorded by the Company requires interpretations of complex rules and regulations of various tax jurisdictions throughout the world. The Company has recognized deferred tax assets and liabilities for temporary differences, operating losses, and tax-credit carryforwards.

The deferred tax assets may be reduced 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. The Company routinely assesses the realizability of its deferred tax assets by analyzing the reversal periods of available net operating loss carryforwards and credit carryforwards, temporary differences in tax assets and liabilities, the availability of tax planning strategies, and estimates of future taxable income and other factors.

The Company also routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts, including interest where appropriate. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position.

Judgments and uncertainties The accruals for deferred tax assets and liabilities, including deferred state income tax assets and liabilities, are subject to significant judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. The assessment of potential uncertain tax positions requires a significant amount of judgment and are reviewed and adjusted on a periodic basis, taking into consideration the progress of ongoing tax audits, case law, and new legislation. Although management considers its tax accruals adequate, material changes in these accruals may occur in the future based on the progress of ongoing tax audits, changes in legislation, and resolution of pending tax matters. Additionally, numerous judgments and assumptions are inherent in management's estimates of future taxable income used to assess the realizability of certain deferred tax assets. The estimates used are based on assumptions of proved oil and gas reserves, commodity prices, and development assumptions that are consistent with the Company's internal business plans.

Contingencies

Methodology The Company is subject to various legal proceedings, claims, and liabilities that arise in the ordinary course of business. Except for contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses when such losses are probable and reasonably estimable. If the Company determines that a loss is probable and cannot estimate a specific amount for that loss, but can estimate a range of loss, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. The Company's in-house legal counsel personnel regularly assess contingent liabilities and, in certain circumstances, consult with third-party legal counsel or consultants to assist in the evaluation of the Company's liability for these contingencies.

Judgments and uncertainties Management makes judgments and estimates when it establishes liabilities for litigation and other contingent matters. Estimates of litigation-related liabilities are based on the facts and circumstances of the individual case and on information currently available to the Company. The extent of information available varies based on the status of the litigation and the Company's evaluation of the claim and legal arguments. In future periods, a number of factors could significantly change the Company's estimate of litigation-related liabilities, including discovery activities; briefings filed with the relevant court; rulings from the court made pre-trial, during trial, or at the conclusion of any trial; and similar cases involving other plaintiffs and defendants that may set or change legal precedent. As events unfold throughout the litigation process, the Company evaluates the available information and may consult with third-party legal counsel to determine whether liability accruals should be established or adjusted.

RECENT ACCOUNTING DEVELOPMENTS

See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of recent accounting developments affecting the Company.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risks are attributable to fluctuations in energy prices and interest rates. These risks can affect revenues and cash flows, and the Company's risk-management policies provide for the use of derivative instruments to manage these risks. The types of commodity derivative instruments used by the Company include futures, swaps, options, and fixed-price physical-delivery contracts. The volume of commodity derivatives entered into by the Company is governed by risk-management policies and may vary from year to year. Both exchange and over-the-counter traded derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company's derivative and financial instruments, see Note 11—Derivative Instruments in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

COMMODITY-PRICE RISK

The Company's most significant market risk relates to prices for oil, natural gas, and NGLs. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Company's oil and gas properties or goodwill may be required if commodity prices experience a significant decline. Below is a sensitivity analysis for the Company's commodity-price-related derivative instruments.

Derivative Instruments Held for Non-Trading Purposes The Company had derivative instruments in place to reduce the price risk associated with future production of 32 MMBbls of oil at December 31, 2018, with a net derivative asset position of $171 million. Based on actual derivative contractual volume, a 10% increase in underlying commodity prices would reduce the fair value of these derivatives by $67 million, while a 10% decrease in underlying commodity prices would increase the fair value of these derivatives by $56 million. However, any cash received or paid to settle these derivatives would be substantially offset by the sales value of production covered by the derivative instruments.

For additional information regarding the Company's marketing activities, see Items 1 and 2 of this Form 10-K.

INTEREST-RATE RISK

Borrowings, if any, under each of the 364-Day Facility, the APC RCF, the WES RCF, the WES 364-Day Facility, and the WGP RCF are subject to variable interest rates. The remaining balance of Anadarko's short-term and long-term borrowings has fixed interest rates. The Company has $2.9 billion of LIBOR-based obligations that are presented on the Company's Consolidated Balance Sheets net of preferred investments in two noncontrolled entities. These obligations give rise to minimal net interest-rate risk because coupons on the related preferred investments are also LIBOR-based. While a 10% change in the applicable benchmark interest rate would not materially impact the Company's interest cost, it would affect the fair value of outstanding fixed-rate debt.

At December 31, 2018, the Company had a net derivative liability position of $1.2 billion related to interest-rate swaps. A 10% increase (decrease) in the LIBOR interest-rate curve would decrease (increase) the aggregate fair value of outstanding interest-rate swap agreements by $92 million. However, any change in the interest-rate derivative gain or loss could be substantially offset by changes in actual borrowing costs associated with future debt issuances. For a summary of the Company's outstanding interest-rate derivative positions, see Note 11—Derivative Instruments in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF MANAGEMENT

Management prepared, and is responsible for, the Consolidated Financial Statements and the other information appearing in this annual report. The Consolidated Financial Statements present fairly the Company's financial condition, results of operations, and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its Consolidated Financial Statements, the Company includes amounts that are based on estimates and judgments that Management believes are reasonable under the circumstances. The Company's financial statements have been audited by KPMG LLP, an independent registered public accounting firm appointed by the Audit Committee of the Board of Directors. Management has made available to KPMG LLP all of the Company's financial records and related data, as well as the minutes of the stockholders' and Directors' meetings.

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Anadarko's internal control system was 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.

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.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2018. This assessment was based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission. Based on our assessment, we believe that the Company's internal control over financial reporting was effective as of December 31, 2018.

KPMG LLP has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2018.

/s/ R. A. WALKER

R. A. Walker
Chairman and Chief Executive Officer

/s/ BENJAMIN M. FINK

Benjamin M. Fink
Executive Vice President, Finance and Chief Financial Officer

February 14, 2019

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Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Anadarko Petroleum Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited Anadarko Petroleum Corporation and subsidiaries' (the Company) 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. 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 Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated February 14, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible 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 Report of Management – *Management's Assessment of Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ KPMG LLP

Houston, Texas
February 14, 2019

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Anadarko Petroleum Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries (the Company) as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements 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 years in the three-year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), 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, and our report dated February 14, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of accounting for revenue recognition in 2018 due to the adoption of Accounting Standards Codification Topic 606 *Revenue from Contracts with Customers.*

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 1981.

Houston, Texas
February 14, 2019

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
millions except per-share amounts	**2018**	2017	2016
Revenues and Other			
Oil sales	**$ 9,206**	$ 6,552	$ 4,668
Natural-gas sales	**1,005**	1,348	1,564
Natural-gas liquids sales	**1,271**	1,069	921
Gathering, processing, and marketing sales	**1,588**	2,000	1,294
Gains (losses) on divestitures and other, net	**312**	939	(578)
Total	**13,382**	11,908	7,869
Costs and Expenses			
Oil and gas operating	**1,153**	988	807
Oil and gas transportation	**878**	914	1,002
Exploration	**459**	2,535	944
Gathering, processing, and marketing	**1,047**	1,552	1,083
General and administrative	**1,084**	994	1,223
Depreciation, depletion, and amortization	**4,254**	4,279	4,301
Production, property, and other taxes	**826**	582	536
Impairments	**800**	408	227
Other operating expense	**262**	221	118
Total	**10,763**	12,473	10,241
Operating Income (Loss)	**2,619**	(565)	(2,372)
Other (Income) Expense			
Interest expense	**947**	932	890
(Gains) losses on early extinguishment of debt	**(2)**	2	155
(Gains) losses on derivatives, net	**130**	135	286
Other (income) expense, net	**59**	54	126
Total	**1,134**	1,123	1,457
Income (Loss) Before Income Taxes	**1,485**	(1,688)	(3,829)
Income tax expense (benefit)	**733**	(1,477)	(1,021)
Net Income (Loss)	**752**	(211)	(2,808)
Net income (loss) attributable to noncontrolling interests	**137**	245	263
Net Income (Loss) Attributable to Common Stockholders	**$ 615**	$ (456)	$ (3,071)
Per Common Share			
Net income (loss) attributable to common stockholders—basic	**$ 1.20**	$ (0.85)	$ (5.90)
Net income (loss) attributable to common stockholders—diluted	**$ 1.20**	$ (0.85)	$ (5.90)
Average Number of Common Shares Outstanding—Basic	**504**	548	522
Average Number of Common Shares Outstanding—Diluted	**504**	548	522

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
millions	**2018**	2017	2016
Net Income (Loss)	**$ 752**	$ (211)	$ (2,808)
Other Comprehensive Income (Loss)			
Adjustments for derivative instruments			
Cumulative effect of accounting change [(1)]	**(7)**	—	—
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**3**	3	8
Income taxes on reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**(1)**	(1)	(3)
Total adjustments for derivative instruments, net of taxes	**(5)**	2	5
Adjustments for pension and other postretirement plans			
Cumulative effect of accounting change [(1)]	**(66)**	—	—
Net gain (loss) incurred during period	**50**	(14)	(175)
Income taxes on net gain (loss) incurred during period	**(11)**	4	68
Amortization of net actuarial (gain) loss to other (income) expense, net	**74**	116	188
Income taxes on amortization of net actuarial (gain) loss	**(20)**	(40)	(73)
Amortization of net prior service (credit) cost to other (income) expense, net	**(24)**	(25)	(34)
Income taxes on amortization of net prior service (credit) cost	**5**	10	13
Total adjustments for pension and other postretirement plans, net of taxes	**8**	51	(13)
Total	**3**	53	(8)
Comprehensive Income (Loss)	**755**	(158)	(2,816)
Comprehensive income (loss) attributable to noncontrolling interests	**137**	245	263
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ 618**	$ (403)	$ (3,079)

(1) Beginning January 1, 2018, the Company adopted ASU 2018-02, *Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.* See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* for further information.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31,	
millions except per-share amounts	**2018**	2017
ASSETS		
Current Assets		
Cash and cash equivalents ($92 and $80 related to VIEs)	**$ 1,295**	$ 4,553
Accounts receivable (net of allowance of $13 and $14)		
Customers ($138 and $106 related to VIEs)	**1,491**	1,222
Others ($15 and $19 related to VIEs)	**535**	607
Other current assets	**474**	380
Total	**3,795**	6,762
Net properties and equipment (net of accumulated depreciation, depletion, and amortization of $37,905 and $34,107) ($6,612 and $5,731 related to VIEs)	**28,615**	27,451
Other Assets ($868 and $579 related to VIEs)	**2,336**	2,211
Goodwill and Other Intangible Assets ($1,163 and $1,191 related to VIEs)	**5,630**	5,662
Total Assets	**$ 40,376**	$ 42,086
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable		
Trade ($263 and $305 related to VIEs)	**$ 2,003**	$ 1,894
Other ($15 and $1 related to VIEs)	**161**	266
Short-term debt - Anadarko [(1)]	**919**	142
Short-term debt - WES and WGP	**28**	—
Current asset retirement obligations	**252**	294
Other current liabilities	**1,295**	1,310
Total	**4,658**	3,906
Long-term Debt		
Long-term debt - Anadarko [(1)]	**10,683**	12,054
Long-term debt - WES and WGP	**4,787**	3,493
Total	**15,470**	15,547
Other Long-term Liabilities		
Deferred income taxes	**2,437**	2,234
Asset retirement obligations ($260 and $143 related to VIEs)	**2,847**	2,500
Other	**4,021**	4,109
Total	**9,305**	8,843
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 576.6 million and 574.2 million shares issued)	**57**	57
Paid-in capital	**12,393**	12,000
Retained earnings	**1,245**	1,109
Treasury stock (87.2 million and 43.4 million shares)	**(4,864)**	(2,132)
Accumulated other comprehensive income (loss)	**(335)**	(338)
Total Stockholders' Equity	**8,496**	10,696
Noncontrolling interests	**2,447**	3,094
Total Equity	**10,943**	13,790
Total Liabilities and Equity	**$ 40,376**	$ 42,086

Parenthetical references reflect amounts as of December 31, 2018, and December 31, 2017.
VIE amounts relate to WGP and WES. See *Note 25—Variable Interest Entities*.

(1) Excludes WES and WGP.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

	Total Stockholders' Equity						
millions	Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total Equity
Balance at December 31, 2015	$ 52	$ 9,265	$ 4,880	$ (995)	$ (383)	$ 2,638	$ 15,457
Net income (loss)	—	—	(3,071)	—	—	263	(2,808)
Common stock issued	5	2,150	—	—	—	—	2,155
Share-based compensation expense	—	197	—	—	—	—	197
Dividends—common stock	—	—	(105)	—	—	—	(105)
Repurchases of common stock	—	—	—	(38)	—	—	(38)
Subsidiary equity transactions	—	263	—	—	—	746	1,009
Distributions to noncontrolling interest owners	—	—	—	—	—	(362)	(362)
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	5	—	5
Adjustments for pension and other postretirement plans	—	—	—	—	(13)	—	(13)
Balance at December 31, 2016	57	11,875	1,704	(1,033)	(391)	3,285	15,497
Net income (loss)	—	—	(456)	—	—	245	(211)
Share-based compensation expense	—	163	—	—	—	—	163
Dividends—common stock	—	—	(111)	—	—	—	(111)
Repurchases of common stock	—	—	—	(1,099)	—	—	(1,099)
Subsidiary equity transactions	—	(35)	—	—	—	9	(26)
Distributions to noncontrolling interest owners	—	—	—	—	—	(445)	(445)
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	2	—	2
Adjustments for pension and other postretirement plans	—	—	—	—	51	—	51
Cumulative effect of accounting change	—	(3)	(28)	—	—	—	(31)
Balance at December 31, 2017	**57**	**12,000**	**1,109**	**(2,132)**	**(338)**	**3,094**	**13,790**
Net income (loss)	**—**	**—**	**615**	**—**	**—**	**137**	**752**
Common stock issued	**—**	**7**	**—**	**—**	**—**	**—**	**7**
Share-based compensation expense	**—**	**169**	**—**	**—**	**—**	**—**	**169**
Dividends—common stock	**—**	**—**	**(528)**	**—**	**—**	**—**	**(528)**
Repurchases of common stock	**—**	**—**	**—**	**(2,732)**	**—**	**—**	**(2,732)**
Subsidiary equity transactions	**—**	**(15)**	**—**	**—**	**—**	**34**	**19**
Settlement of tangible equity units	**—**	**232**	**—**	**—**	**—**	**(300)**	**(68)**
Distributions to noncontrolling interest owners	**—**	**—**	**—**	**—**	**—**	**(495)**	**(495)**
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**—**	**—**	**—**	**—**	**2**	**—**	**2**
Adjustments for pension and other postretirement plans	**—**	**—**	**—**	**—**	**74**	**—**	**74**
Cumulative effect of accounting change[1]	**—**	**—**	**49**	**—**	**(73)**	**(23)**	**(47)**
Balance at December 31, 2018	**$ 57**	**$ 12,393**	**$ 1,245**	**$ (4,864)**	**$ (335)**	**$ 2,447**	**$ 10,943**

(1) Beginning January 1, 2018, the Company adopted ASU 2014-09, Revenue from Contracts with Customers (Topic 606), and ASU 2018-02, *Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.* See Note 1—Summary of Significant Accounting Policies in the *Notes to Consolidated Financial Statements* for further information.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
millions	2018	2017	2016
Cash Flows from Operating Activities			
Net income (loss)	$ 752	$ (211)	$ (2,808)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
Depreciation, depletion, and amortization	4,254	4,279	4,301
Deferred income taxes	139	(2,169)	(1,238)
Dry hole expense and impairments of unproved properties	246	2,221	613
Impairments	800	408	227
(Gains) losses on divestitures, net	(20)	(674)	757
(Gains) losses on early extinguishment of debt	(2)	2	155
Total (gains) losses on derivatives, net	138	131	292
Operating portion of net cash received (paid) in settlement of derivative instruments	(545)	25	267
Other	294	303	342
Changes in assets and liabilities			
(Increase) decrease in accounts receivable	(211)	(147)	677
Increase (decrease) in accounts payable and other current liabilities	348	(32)	(443)
Other items, net	(264)	(127)	(142)
Net cash provided by (used in) operating activities	5,929	4,009	3,000
Cash Flows from Investing Activities			
Additions to properties and equipment	(6,183)	(5,031)	(3,505)
Acquisition of businesses	—	25	(1,740)
Divestitures of properties and equipment and other assets	417	4,008	2,356
Other, net	(216)	(32)	147
Net cash provided by (used in) investing activities	(5,982)	(1,030)	(2,742)
Cash Flows from Financing Activities			
Borrowings, net of issuance costs	2,343	369	6,042
Repayments of debt	(1,689)	(58)	(6,832)
Financing portion of net cash received (paid) for derivative instruments	12	(165)	(333)
Increase (decrease) in outstanding checks	(39)	(43)	(103)
Dividends paid	(528)	(111)	(105)
Repurchases of common stock	(2,732)	(1,092)	(38)
Issuances of common stock	7	—	2,188
Sales of subsidiary units	—	—	1,163
Distributions to noncontrolling interest owners	(495)	(445)	(362)
Proceeds from conveyance of future hard-minerals royalty revenues, net of transaction costs	—	—	413
Payments of future hard-minerals royalty revenues conveyed	(50)	(50)	(25)
Other financing activities	(6)	(18)	—
Net cash provided by (used in) financing activities	(3,177)	(1,613)	2,008
Effect of exchange rate changes on cash, cash equivalents, restricted cash, and restricted cash equivalents	(15)	—	17
Net Increase (Decrease) in Cash, Cash Equivalents, Restricted Cash, and Restricted Cash Equivalents	(3,245)	1,366	2,283
Cash, Cash Equivalents, Restricted Cash, and Restricted Cash Equivalents at Beginning of Period	4,674	3,308	1,025
Cash, Cash Equivalents, Restricted Cash, and Restricted Cash Equivalents at End of Period	$ 1,429	$ 4,674	$ 3,308

See accompanying Notes to Consolidated Financial Statements.

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production, and sale of oil, natural gas, and NGLs and is continuing to advance its Mozambique LNG project toward FID. In addition, the Company engages in gathering, compressing, treating, processing, and transporting of natural gas; gathering, stabilizing, and transporting of oil and NGLs; and gathering and disposing of produced water. The Company also participates in the hard-minerals business through royalty arrangements.

Basis of Presentation The consolidated financial statements have been prepared in conformity with GAAP. Certain prior-period amounts have been reclassified to conform to the current-year presentation.

The consolidated financial statements include the accounts of Anadarko and subsidiaries in which Anadarko holds, directly or indirectly, more than 50% of the voting rights and VIEs for which Anadarko is the primary beneficiary. The Company has determined that WGP and WES are VIEs. Anadarko is considered the primary beneficiary and consolidates WGP and WES. WGP and WES function with capital structures that are separate from Anadarko, consisting of their own debt instruments and publicly traded common units. All intercompany transactions have been eliminated. Undivided interests in oil and natural-gas exploration and production joint ventures are consolidated on a proportionate basis. Investments in noncontrolled entities that Anadarko has the ability to exercise significant influence over operating and financial policies and VIEs for which Anadarko is not the primary beneficiary are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for the Company's proportionate share of earnings, losses, and distributions. Investments are included in other assets on the Company's Consolidated Balance Sheets.

Use of Estimates The preparation of financial statements in accordance with GAAP requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, including those related to proved reserves; the value of properties and equipment; goodwill; intangible assets; AROs; litigation liabilities; environmental liabilities; pension assets, liabilities, and costs; income taxes; and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

1. Summary of Significant Accounting Policies (Continued)

Fair Value Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1—Inputs represent unadjusted quoted prices in active markets for identical assets or liabilities (for example, exchange-traded futures contracts for which parties are willing to transact at the exchange-quoted price).

Level 2—Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3—Inputs that are not observable from objective sources such as the Company's internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the Company's internally developed present value of future cash flows model that underlies the fair-value measurement).

In determining fair value, the Company uses observable market data when available or models that incorporate observable market data. When the Company is required to measure fair value and there is not a market-observable price for the asset or liability or for a similar asset or liability, the Company uses the cost or income approach depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of future net cash flows and discounts the expected cash flows using a commensurate risk-adjusted discount rate. Such evaluations involve significant judgment, and the results are based on expected future events or conditions such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, economic and regulatory climates, and other factors, most of which are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs, and other factors and are consistent with assumptions used in the Company's business plans and investment decisions.

In arriving at fair-value estimates, the Company uses relevant observable inputs available for the valuation technique employed. If a fair-value measurement reflects inputs at multiple levels within the hierarchy, the fair-value measurement is characterized based on the lowest level of input that is significant to the fair-value measurement. For Anadarko, recurring fair-value measurements are performed for interest-rate derivatives, commodity derivatives, and investments in trading securities.

The carrying amount of cash and cash equivalents, accounts receivable, and accounts payable reported on the Company's Consolidated Balance Sheets approximates fair value. The fair value of debt is the estimated amount the Company would have to pay to repurchase its debt, including any premium or discount attributable to the difference between the stated interest rate and market interest rate at each balance sheet date. Debt fair values, as disclosed in *Note 13—Debt and Interest Expense*, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments.

Non-financial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a business combination or through a non-monetary exchange transaction, intangible assets, goodwill, AROs, exit or disposal costs, and capital lease assets and liabilities where the present value of lease payments is greater than the fair value of the leased asset.

1. Summary of Significant Accounting Policies (Continued)

Revenues

2018 The Company's revenue recognition accounting policy effective January 1, 2018, is detailed below.

Exploration and Production The Company's oil is sold primarily to marketers, gatherers, and refiners. Natural gas is sold primarily to interstate and intrastate natural-gas pipelines, direct end-users, industrial users, local distribution companies, and natural-gas marketers. NGLs are sold primarily to direct end-users, refiners, and marketers. Payment is generally received from the customer in the month following delivery.

Contracts with customers have varying terms, including spot sales or month-to-month contracts, contracts with a finite term, and life-of-field contracts where all production from a well or group of wells is sold to one or more customers. The Company recognizes sales revenues for oil, natural gas, and NGLs based on the amount of each product sold to a customer when control transfers to the customer. Generally, control transfers at the time of delivery to the customer at a pipeline interconnect, the tailgate of a processing facility, or as a tanker lifting is completed. Revenue is measured based on the contract price, which may be index-based or fixed, and may include adjustments for market differentials and downstream costs incurred by the customer, including gathering, transportation, and fuel costs. For natural gas and NGLs sold on our behalf by a processor, revenue is typically measured based on the price the processor receives for the sale, less certain costs withheld by the processor.

Revenues are recognized for the sale of Anadarko's net share of production volume. Sales on behalf of other working interest owners and royalty interest owners are not recognized as revenues.

The Company enters into buy/sell arrangements related to the transportation of a portion of its oil production. These buy/sell transactions are recorded net in oil and gas transportation expense in the Company's Consolidated Statements of Income.

WES Midstream and Other Midstream Anadarko provides gathering, compressing, treating, processing, stabilizing, transporting, and disposal services pursuant to a variety of contracts. Under these arrangements, the Company receives fees and/or retains a percentage of products or a percentage of the proceeds from the sale of the customer's products. These revenues are included in gathering, processing, and marketing sales in the Company's Consolidated Statements of Income. Payment is generally received from the customer in the month of service or the month following the service. Contracts with customers generally have initial terms ranging from 5 to 10 years.

Revenue is recognized for fee-based gathering and processing services in the month of service based on the volume delivered by the customer. Revenues are valued based on the rate in effect for the month of service when the fee is either the same rate per unit over the contract term or when the fee escalates and the escalation factor approximates inflation. The Company may charge additional service fees to customers for a portion of the contract term (i.e., for the first year of a contract or until reaching a volume threshold) due to the significant upfront capital investment. These fees are recognized as revenue over the expected period of customer benefit, generally the life of the related properties. Deficiency fees, which are charged to the customer if they do not meet minimum delivery requirements, are recognized over the performance period based on an estimate of the deficiency fees that will be billed upon completion of the performance period.

The Company's midstream business also purchases natural-gas volume from producers at the wellhead or production facility, typically at an index price, and charges the producer fees associated with the downstream gathering and processing services. These fees are treated as a reduction of the purchase cost when the fees relate to services performed after control of the product has transferred to Anadarko. If the fees relate to services performed before control of the product has transferred to Anadarko, the fees are treated as Gathering, processing and marketing sales revenues. Revenue is recognized, along with cost of product expense related to the sale, when the purchased product is sold to a third party.

Revenue from percentage of proceeds gathering and processing contracts is recognized net of the cost of product for purchases from service customers when the Company is acting as their agent in the product sale, and any fees charged on these percentage of proceeds contracts are recognized in service revenues.

1. Summary of Significant Accounting Policies (Continued)

2017 This section reflects the Company's revenue recognition policies through December 31, 2017, prior to the adoption of ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. The Company's oil is sold primarily to marketers, gatherers, and refiners. Natural gas is sold primarily to interstate and intrastate natural-gas pipelines, direct end-users, industrial users, local distribution companies, and natural-gas marketers. NGLs are sold primarily to direct end-users, refiners, and marketers.

The Company recognizes sales revenues for oil, natural gas, and NGLs based on the amount of each product sold to purchasers when delivery to the purchaser has occurred and title has transferred. This occurs when product has been delivered to a pipeline or when a tanker lifting has occurred. The Company follows the sales method of accounting for natural-gas production imbalances. If the Company's sales volume for a well exceed the Company's proportionate share of production from the well, a liability is recognized to the extent that the Company's share of estimated remaining recoverable reserves from the well is insufficient to satisfy this imbalance. No receivables are recorded for those wells on which the Company has taken less than its proportionate share of production.

Anadarko provides gathering, processing, treating, and transporting services pursuant to a variety of contracts. Under these arrangements, the Company receives fees or retains a percentage of products or a percentage of the proceeds from the sale of products and recognizes revenue at the time services are performed or product is sold. These revenues are included in gathering, processing, and marketing sales in the Company's Consolidated Statements of Income.

The Company enters into buy/sell arrangements related to the transportation of a portion of its oil production. Under these arrangements, barrels are sold to a third party at a location-based contract price and subsequently repurchased by the Company at a downstream location. The difference in value between the sale and purchase price represents the transportation fee from the lease or certain gathering locations to more liquid markets. These arrangements are often required by private transporters. These transactions are reported on a net basis and included in oil and gas transportation in the Company's Consolidated Statements of Income.

Cash Equivalents and Restricted Cash Equivalents The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents or restricted cash equivalents. The cash equivalents and restricted cash equivalents balance at December 31, 2018, includes commercial paper and investments in government money market funds in which the carrying value approximates fair value.

Accounts Receivable and Allowance for Uncollectible Accounts The Company conducts credit analyses of customers prior to making any sales to new customers or increasing credit for existing customers. Based on these analyses, the Company may require a standby letter of credit or a financial guarantee. The Company charges uncollectible accounts receivable against the allowance for uncollectible accounts when it determines collection will no longer be pursued.

Inventories Commodity inventories are stated at the lower of average cost or net realizable value.

1. Summary of Significant Accounting Policies (Continued)

Properties and Equipment Properties and equipment are stated at cost less accumulated DD&A. Costs of improvements that extend the lives of existing properties are capitalized. Maintenance and repairs are expensed as incurred. Upon retirement or sale, the cost of properties and equipment, net of the related accumulated DD&A, is removed and, if appropriate, gain or loss is recognized in gains (losses) on divestitures and other, net in the Company's Consolidated Statements of Income.

Oil and Gas Properties The Company applies the successful efforts method of accounting for oil and gas properties. Exploration costs, such as exploratory geological and geophysical costs, delay rentals, and exploration overhead, are charged against earnings as incurred. Exploratory drilling costs are initially capitalized pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities, in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, analyzing whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed.

Acquisition costs of unproved properties are periodically assessed for impairment and are transferred to proved properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment, based on the Company's current exploration plans, and a valuation allowance is provided if impairment is indicated. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis (thereby establishing a valuation allowance) over the average lease terms at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment. Costs of expired or abandoned leases are charged against the valuation allowance, while costs of productive leases are transferred to proved properties. Costs of maintaining and retaining unproved properties, as well as amortization of individually insignificant leases and impairment of unsuccessful leases, are included in exploration expense in the Company's Consolidated Statements of Income.

Capitalized Interest For significant projects, interest is capitalized as part of the historical cost of developing and constructing assets. Significant oil and gas investments in unproved properties, significant exploration and development projects that have not commenced production, significant midstream development activities that are in progress, and investments in equity-method affiliates that are undergoing the construction of assets that have not commenced principle operations qualify for interest capitalization. Interest is capitalized until the asset is ready for service. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment. See *Note 13—Debt and Interest Expense*.

1. Summary of Significant Accounting Policies (Continued)

Asset Retirement Obligations AROs associated with the retirement of tangible long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value and is included in DD&A in the Company's Consolidated Statements of Income. If estimated future costs of AROs change, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. See *Note 15—Asset Retirement Obligations*.

Impairments Properties and equipment are reviewed for impairment when facts and circumstances indicate that net book values may not be recoverable. In performing this review, an undiscounted cash flow test is performed at the lowest level for which identifiable cash flows are independent of cash flows from other assets. If the sum of the undiscounted future net cash flows is less than the net book value of the property, an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value. See *Note 6—Impairments*.

Depreciation, Depletion, and Amortization Costs of drilling and equipping successful wells, costs to construct or acquire facilities other than offshore platforms, associated asset retirement costs, and capital lease assets used in oil and gas activities are depreciated using the UOP method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties and costs to construct or acquire offshore platforms and associated asset retirement costs, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves. Mineral properties are also depleted using the UOP method. All other properties are stated at historical acquisition cost, net of impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 40 years for buildings, and up to 40 years for gathering facilities.

Goodwill and Other Intangible Assets Anadarko has allocated goodwill to the following reporting units: Exploration and Production; WES Gathering and Processing; WES Transportation; and Other Midstream. Goodwill is subject to annual impairment testing in October (or more frequent testing as circumstances dictate). Anadarko's goodwill impairment test first assesses qualitative factors to determine whether goodwill is impaired. If the qualitative assessment indicates that it is more likely than not that the fair value of a reporting unit is less than its carrying amount including goodwill, the Company will then perform a quantitative goodwill impairment test. Changes in goodwill may result from, among other things, impairments, acquisitions, or divestitures. See *Note 8—Goodwill and Other Intangible Assets*.

Other intangible assets represent contractual rights obtained in connection with business combinations that had favorable contractual terms relative to market at the acquisition date as well as customer-related intangible assets, including customer relationships established by acquired contracts. Other intangible assets are amortized over their estimated useful lives and are assessed for impairment with the associated long-lived asset group whenever impairment indicators are present. See *Note 8—Goodwill and Other Intangible Assets*.

Derivative Instruments Anadarko uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Derivatives are carried on the balance sheet at fair value and are included in other current assets, other assets, other current liabilities, or other long-term liabilities, depending on the derivative position and the expected timing of settlement, unless they satisfy the normal purchases and sales exception criteria. Where the Company has the contractual right and intends to net settle, derivative assets and liabilities are reported on a net basis.

Gains and losses on derivative instruments are recognized currently in earnings. Net losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and will be reclassified to earnings in future periods as the economic transactions to which the derivatives relate affect earnings. See *Note 11—Derivative Instruments*.

1. Summary of Significant Accounting Policies (Continued)

Legal Contingencies The Company is subject to legal proceedings, claims, and liabilities that arise in the ordinary course of business. Except for legal contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses associated with legal claims when such losses are probable and reasonably estimable. If the Company determines that a loss is probable and cannot estimate a specific amount for that loss but can estimate a range of loss, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. Estimates are adjusted as additional information becomes available or circumstances change. Legal defense costs associated with loss contingencies are expensed in the period incurred. See *Note 18—Contingencies*.

Environmental Contingencies The Company is subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. Except for environmental contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses associated with environmental obligations when such losses are probable and reasonably estimable. Accruals for estimated environmental losses are recognized no later than at the time the remediation feasibility study, or the evaluation of response options, is complete. These accruals are adjusted as additional information becomes available or circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable. See *Note 18—Contingencies*.

Noncontrolling Interests Noncontrolling interests represent third-party ownership in the net assets of the Company's consolidated subsidiaries and are presented as a component of equity. Changes in Anadarko's ownership interests in subsidiaries that do not result in deconsolidation are recognized in equity. See *Note 24—Noncontrolling Interests*.

Income Taxes The Company files various U.S. federal, state, and foreign income tax returns. The impact of changes in tax regulations are reflected when enacted. Deferred federal, state, and foreign income taxes are provided on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis. The Company routinely assesses the realizability of its deferred tax assets. If the Company concludes that it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through final settlement with a taxing authority. Interest and penalties related to unrecognized tax benefits are recognized in income tax expense (benefit). The Company uses the flow-through method to account for its investment tax credits. See *Note 14—Income Taxes*.

Share-Based Compensation The Company accounts for share-based compensation at fair value. The Company grants equity-classified awards, including stock options and non-vested equity shares (restricted stock awards and units). The Company may also grant equity-classified and liability-classified awards based on a comparison of the Company's TSR to the TSR of a predetermined group of peer companies (performance units).

The fair value of stock option awards is determined using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of Anadarko common stock. For other share-based compensation awards, fair value is determined using a Monte Carlo simulation.

The Company records compensation cost, net of actual forfeitures, for share-based compensation awards over the requisite service period using the straight-line method. For equity-classified share-based compensation awards, expense is recognized based on the grant-date fair value. For liability-classified share-based compensation awards, expense is recognized for those awards expected to ultimately be paid. The amount of expense reported for liability-classified awards is adjusted for fair-value changes so that the expense recognized for each award is equivalent to the amount to be paid. See *Note 23—Share-Based Compensation*.

1. Summary of Significant Accounting Policies (Continued)

Recently Adopted Accounting Standards

ASU 2017-07, Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost This ASU requires presentation of service cost in the same line item(s) as other compensation costs arising from services rendered by employees during the period and presentation of the remaining components of net benefit cost in a separate line item outside operating items. Additionally, only the service cost component of net benefit cost will be eligible for capitalization. The Company adopted this ASU on January 1, 2018, with retrospective presentation of the service cost component and the other components of net benefit cost in the income statement and prospective presentation for the capitalization of the service cost component of net benefit cost in assets. Upon adoption, non-service cost components of net periodic benefit costs of $107 million for the year ended December 31, 2017, and $225 million for the year ended December 31, 2016, were reclassified to other (income) expense, net, from G&A; oil and gas operating; gathering, processing, and marketing; and exploration expense.

ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash This ASU requires an entity to explain the changes in the total of cash, cash equivalents, restricted cash, and restricted cash equivalents on the statement of cash flows and to provide a reconciliation of the totals in that statement to the related captions in the balance sheet when the cash, cash equivalents, restricted cash, and restricted cash equivalents are presented in more than one line item on the balance sheet. The Company adopted this ASU using a retrospective approach on January 1, 2018. Adoption did not have a material impact on the Company's consolidated financial statements. See Consolidated Statements of Cash Flows and *Note 26—Supplemental Cash Flow Information* for additional information.

ASU 2014-09, Revenue from Contracts with Customers (Topic 606) This ASU supersedes the revenue recognition requirements and industry-specific guidance under *Revenue Recognition* (*Topic 605)*. Topic 606 requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company adopted Topic 606 on January 1, 2018, using the modified retrospective method applied to contracts that were not completed as of January 1, 2018. Under the modified retrospective method, prior-period financial positions and results will not be adjusted. The cumulative effect adjustment recognized in the opening balances included a reduction to total equity of $47 million. See *Note 2—Revenue from Contracts with Customers* for additional information.

ASU 2018-02, Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income This ASU provides entities the option to reclassify stranded tax effects resulting from the Tax Reform Legislation from accumulated other comprehensive income (AOCI) to retained earnings. In accordance with its accounting policy, the Company releases stranded income tax effects from AOCI in the period the underlying portfolio is liquidated. This ASU allows for the reclassification of stranded tax effects as a result of the change in tax rates from the Tax Reform Legislation to be recorded upon adoption of the ASU, rather than at the actual portfolio liquidation date. The Company adopted this ASU on January 1, 2018, electing to reclassify $73 million from AOCI to retained earnings, including a $2 million federal benefit of state tax impact related to the Tax Reform Legislation.

1. Summary of Significant Accounting Policies (Continued)

Accounting Standards Adopted in 2019

ASU 2016-02, Leases (Topic 842) This ASU requires lessees to recognize a lease liability and a right-of-use (ROU) asset for all leases, including operating leases, with a term greater than 12 months on the balance sheet. This ASU modifies the definition of a lease and outlines the recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. This standard is effective for periods beginning after December 15, 2018, and in the first quarter of 2019, the Company fully adopted this standard using the modified retrospective method applied to all leases that existed on January 1, 2019. Anadarko made certain elections allowing the Company not to reassess contracts that commenced prior to adoption, to continue applying its current accounting policy for existing or expired land easements, and not to recognize ROU assets or lease liabilities for short-term leases. Upon adoption, the Company recognized approximately $600 million of ROU assets and lease liabilities on its Consolidated Balance Sheet related to leases existing on January 1, 2019. The adoption of this ASU did not have a material impact on the Company's Consolidated Statement of Income or Consolidated Statement of Cash Flows. Anadarko has not identified any material leases in which Anadarko is a lessor. The Company has implemented the necessary changes to its business processes, systems, and controls to support accounting and disclosure requirements under this ASU.

2. Revenue from Contracts with Customers

Change in Accounting Policy As stated above, the Company adopted ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, on January 1, 2018, using the modified retrospective method applied to contracts that were not completed as of January 1, 2018. See Note 1—Summary of Significant Accounting Policies for additional information.

Impacts on Financial Statements

Exploration and Production There were no significant changes to the timing or valuation of revenue recognized for sales of production by the Exploration and Production reporting segment.

WES Midstream and Other Midstream Gathering and processing revenues decreased for contracts where the Company is acting as an agent for its processing customer in the sale of processed volume and increased for contracts with noncash consideration, with an offset to gathering and processing expense upon product sale. The magnitude of these presentation changes in subsequent periods is dependent on future customer volume subject to the impacted contracts and commodity prices for this volume. These presentation changes do not impact net earnings.

The following tables summarize the impacts of adopting Topic 606 on the Company's consolidated financial statements:

CONSOLIDATED BALANCE SHEET	**Impact of Change in Accounting Policy**		
millions	**As Reported**	**Without Adoption of Topic 606**	**Effect of Change** Increase/ (Decrease)
December 31, 2018			
Assets			
Other current assets	**$ 474**	$ 472	$ 2
Net properties and equipment	**28,615**	28,548	67
Other assets	**2,336**	2,326	10
Liabilities			
Other current liabilities	**1,295**	1,290	5
Deferred income taxes	**2,437**	2,441	(4)
Other	**4,021**	3,914	107
Equity			
Total equity	**10,943**	10,972	(29)

2. Revenue from Contracts with Customers (Continued)

CONSOLIDATED STATEMENT OF INCOME	Impact of Change in Accounting Policy		
millions	As Reported	Without Adoption of Topic 606	Effect of Change Increase/ (Decrease)
Year Ended December 31, 2018			
Revenues			
Gathering, processing, and marketing sales	**$ 1,588**	$ 2,592	$ (1,004)
Gains (losses) on divestitures and other, net	**312**	316	(4)
Expenses			
Gathering, processing, and marketing	**1,047**	2,075	(1,028)
Income tax expense (benefit)	**733**	731	2
Net income (loss) attributable to noncontrolling interests	**137**	127	10
Net Income (Loss) Attributable to Common Stockholders	**$ 615**	$ 607	$ 8

Disaggregation of Revenue from Contracts with Customers The following table disaggregates revenue by significant product type and segment:

millions	Exploration & Production	WES Midstream	Other Midstream	Other and Intersegment Eliminations	Total
Year Ended December 31, 2018					
Oil sales	$ 9,206	$ —	$ —	$ —	$ 9,206
Natural-gas sales	1,005	—	—	—	1,005
Natural-gas liquids sales	1,271	—	—	—	1,271
Gathering, processing, and marketing sales(1)	—	1,997	416	21	2,434
Other, net	30	—	1	97	128
Total Revenue from Customers	**$ 11,512**	**$ 1,997**	**$ 417**	**$ 118**	**$14,044**
Gathering, processing, and marketing sales(2)	—	(8)	8	(846)	(846)
Gains (losses) on divestitures, net	20	1	10	(11)	20
Other, net	(34)	173	40	(15)	164
Total Revenue from Other than Customers	**$ (14)**	**$ 166**	**$ 58**	**$ (872)**	**$ (662)**
Total Revenue and Other	**$ 11,498**	**$ 2,163**	**$ 475**	**$ (754)**	**$13,382**

(1) The amount in Other and Intersegment Eliminations primarily represents sales of third-party natural gas and NGLs of $957 million and intersegment eliminations of $(876) million for the year ended December 31, 2018.

(2) The amount in Other and Intersegment Eliminations primarily represents purchases of third-party natural gas and NGLs. Although these purchases are reported net in gathering, processing, and marketing sales in the Company's Consolidated Statements of Income, they are shown separately on this table as the purchases are not considered revenue from customers.

2. Revenue from Contracts with Customers (Continued)

Contract Liabilities Contract liabilities primarily relate to midstream fees and capital reimbursements that are charged to customers for only a portion of the contract term and must be recognized as revenues over the expected period of benefit, fixed and variable fees that are received from customers but revenue recognition is deferred under midstream cost of service contracts, and hard-minerals bonus payments received from customers that must be recognized as revenue over the expected period of benefit. The following table summarizes the current period activity related to contract liabilities from contracts with customers:

millions		
Balance at December 31, 2017	**$**	**37**
Increase due to cumulative effect of adopting Topic 606		**98**
Increase due to cash received, excluding revenues recognized in the period		**66**
Increase due to assets received from customer		**13**
Decrease due to revenue recognized		**(42)**
Decrease due to change in estimated consideration		**(22)**
Balance at December 31, 2018	**$**	**150**
Contract liabilities at December 31, 2018		
Other current liabilities	**$**	**31**
Other long-term liabilities - other		**119**
Total contract liabilities from contracts with customers	**$**	**150**

Transaction Price Allocated to Remaining Performance Obligations Revenue expected to be recognized from certain performance obligations that are unsatisfied as of December 31, 2018, is reflected in the table below. The Company applies the optional exemptions in Topic 606 and does not disclose consideration for remaining performance obligations with an original expected duration of one year or less or for variable consideration related to unsatisfied performance obligations. Therefore, the following table represents only a small portion of Anadarko's expected future consolidated revenues as future revenue from the sale of most products and services is dependent on future production or variable customer volume and variable commodity prices for this volume.

millions		**Exploration & Production**		**WES Midstream**		**Other Midstream**		**Other and Intersegment Eliminations**		**Total**
2019	$	104	$	470	$	204	$	(432)	$	346
2020		103		554		293		(614)		336
2021		103		534		361		(681)		317
2022		7		530		417		(740)		214
2023		7		489		424		(750)		170
Thereafter		58		1,802		2,763		(4,077)		546
Total	$	382	$	4,379	$	4,462	$	(7,294)	$	1,929

3. Commodity Inventories

The following summarizes the major classes of commodity inventories included in other current assets at December 31:

millions		2018		2017
Oil	$	139	$	165
Natural gas		18		29
NGLs		78		122
Total commodity inventories	$	235	$	316

4. Divestitures and Assets Held for Sale

Divestitures and Assets Held for Sale The following summarizes the proceeds received and gains (losses) recognized on divestitures and assets held for sale for the years ended December 31:

millions		2018		2017		2016
Proceeds received, net of closing adjustments	$	417	$	4,008	$	2,356
Gains (losses) on divestitures, net [(1)] [(2)]		20		674		(757)

(1) Includes goodwill allocated to divestitures of $209 million in 2017 and $397 million in 2016.
(2) Includes gain of $126 million related to the 2017 property exchange discussed below.

2018 During the year ended December 31, 2018, the Company divested of the following U.S. onshore and Gulf of Mexico assets:

- Alaska nonoperated assets, included in the Exploration and Production and Other Midstream reporting segments, for net proceeds of $370 million and net losses of $33 million in 2018 and $154 million in the fourth quarter of 2017
- Ram Powell nonoperated assets in the Gulf of Mexico, included in the Exploration and Production reporting segment, resulting in a net gain of $67 million

2017 During the year ended December 31, 2017, the Company divested of the following U.S. onshore assets:

- Eagleford assets in South Texas, included in the Exploration and Production reporting segment, for net proceeds of $2.1 billion and a net gain of $729 million
- Eaglebine assets in Southeast Texas, included in the Exploration and Production reporting segment, for net proceeds of $533 million and a net gain of $282 million
- Utah CBM assets, included in the Exploration and Production and WES Midstream reporting segments, for net proceeds of $69 million and a net loss of $52 million
- Marcellus assets in Pennsylvania, included in the Exploration and Production and Other Midstream reporting segments, for net proceeds of $951 million and net losses of $55 million in 2017 and $129 million in 2016
- Moxa assets in Wyoming, included in the Exploration and Production reporting segment, for net proceeds of $313 million and a net loss of $204 million

Certain nonoperated assets located in Alaska included in the Exploration and Production reporting segment satisfied criteria to be considered held for sale during the fourth quarter of 2017, at which time the Company remeasured these assets to their current fair value using a market approach and Level 2 fair-value measurement and recognized a loss of $154 million. At December 31, 2017, the Company's Consolidated Balance Sheet included long-term assets of $573 million and long-term liabilities of $27 million associated with assets held for sale.

4. Divestitures and Assets Held for Sale (Continued)

2016 During the year ended December 31, 2016, the Company divested of the following U.S. onshore assets:

- Hugoton assets in Kansas, included in the Exploration and Production and WES Midstream reporting segments, for net proceeds of $159 million and a loss of $4 million
- Ozona and Steward assets in West Texas, included in the Exploration and Production and Other Midstream reporting segments, for net proceeds of $221 million and a loss of $52 million
- Wamsutter assets in Wyoming, included in the Exploration and Production reporting segment, for net proceeds of $588 million and a loss of $58 million
- Elm Grove assets in East Texas, included in the Exploration and Production reporting segment, for net proceeds of $89 million and a loss of $64 million
- East Chalk and Carthage assets in East Texas/Louisiana, included in the Exploration and Production and Other Midstream reporting segments, for net proceeds of $1.0 billion and a net loss of $439 million

Certain Marcellus U.S. onshore assets located in Pennsylvania included in the Exploration and Production and Other Midstream reporting segments satisfied criteria to be considered held for sale during the fourth quarter of 2016, at which time the Company remeasured these assets to their current fair value using a market approach and Level 2 fair-value measurement and recognized a loss of $129 million.

Property Exchange On March 17, 2017, WES acquired a third party's 50% nonoperated interest in the DBJV System, now part of the West Texas Complex, in exchange for WES's 33.75% interest in nonoperated Marcellus midstream assets and $155 million in cash. WES recognized a gain of $126 million as a result of this transaction. After the acquisition, the DBJV System is 100% owned by WES and consolidated by Anadarko.

5. Properties and Equipment

The following summarizes properties and equipment at December 31:

millions	2018	2017
Exploration and Production [(1)]	$ 51,941	$ 49,388
WES Midstream	9,250	7,865
Other Midstream	2,908	2,012
Other	2,421	2,293
Gross properties and equipment	$ 66,520	$ 61,558
Less accumulated DD&A	37,905	34,107
Net properties and equipment	$ 28,615	$ 27,451

(1) Includes costs associated with unproved properties of $1.7 billion at December 31, 2018, and $2.4 billion at December 31, 2017.

6. Impairments

Impairments of Long-Lived Assets Impairments of long-lived assets are included in impairment expense in the Company's Consolidated Statements of Income. The following summarizes impairments of long-lived assets and the related post-impairment fair values by segment at December 31:

	2018		2017		2016	
millions	Impairment	Fair Value [(1)]	Impairment	Fair Value [(1)]	Impairment	Fair Value [(1)]
Exploration and Production						
U.S. onshore properties	$ 347	$ 100	$ 2	$ 3	$ 28	$ 617
Gulf of Mexico properties	27	—	227	216	27	61
Cost-method investment	—	—	—	—	59	—
WES Midstream	228	30	176	58	16	3
Other Midstream	53	72	2	—	57	29
Other	145	15	1	—	40	—
Total impairments	$ 800	$ 217	$ 408	$ 277	$ 227	$ 710

(1) Measured as of the impairment date using the income approach and Level 3 inputs. The primary assumptions used to estimate undiscounted future net cash flows include anticipated future production, commodity prices, and capital and operating costs.

2018 Impairments were primarily related to the Company's Greater Natural Buttes oil and gas and midstream properties due to the steep decline in NGL commodity prices in the fourth quarter of 2018 and a gathering system in the DJ basin that was permanently taken out of service in the second quarter of 2018. Impairments also related to hard-minerals properties as a result of the Company's primary consumer of coal stating its intent to retire its existing coal-fired power generation plant earlier than expected, coupled with the outlook for limited new markets for the Company's coal in the Rockies region.

2017 Impairments were primarily related to oil and gas properties in the Gulf of Mexico due to lower forecasted commodity prices and a U.S. onshore midstream property due to a reduced throughput fee as a result of a producer's bankruptcy.

2016 Impairments were primarily related to the uncertain recovery of the Company's Venezuelan cost-method investment, negative developments related to commercial negotiations of a certain midstream asset, impairment of an office building, changes in development plans for certain U.S. onshore oil and gas assets, and a reduction in estimated future cash flows related to an oil and gas property in the Gulf of Mexico.

6. Impairments (Continued)

Impairments of Unproved Properties Impairments of unproved properties are included in exploration expense in the Company's Consolidated Statements of Income.

2018 The Company recognized $159 million of impairments of unproved Gulf of Mexico properties primarily related to GOM blocks where the Company determined it would no longer pursue exploration activities.

2017 The Company recognized $610 million of impairments of unproved Gulf of Mexico properties primarily due to an impairment of $463 million to the Shenandoah project. The unproved property balance related to the Shenandoah project originated from the purchase price allocated to Gulf of Mexico exploration projects from the acquisition of Kerr-McGee Corporation in 2006. The Company also recognized $88 million of impairments of unproved international properties. See *Note 7—Suspended Exploratory Well Costs*.

2016 The Company recognized a $72 million impairment of unproved properties in the Gulf of Mexico and $92 million of unproved international properties primarily in Brazil and Tunisia due to the Company's intentions to not pursue future exploration activities.

It is also reasonably possible that significant declines in commodity prices, further changes to the Company's drilling plans in response to lower prices, reduction of proved and probable reserve estimates, or increases in drilling or operating costs could result in additional impairments.

7. Suspended Exploratory Well Costs

The following summarizes the changes in suspended exploratory well costs at December 31 for each of the last three years:

millions		2018		2017		2016
Balance at January 1	$	525	$	1,230	$	1,124
Additions pending the determination of proved reserves [1]		90		349		490
Divestitures and other		(38)		(36)		(11)
Reclassifications to proved properties		(132)		(41)		(50)
Charges to exploration expense		(1)		(977)		(323)
Balance at December 31	$	444	$	525	$	1,230

[1] Excludes amounts capitalized and subsequently charged to expense within the same year.

2018 During the year ended December 31, 2018, the Company expensed $87 million of exploratory well costs, including $1 million of costs that were suspended as of December 31, 2017.

2017 During the year ended December 31, 2017, exploratory well costs charged to exploration expense primarily related to the following:

Gulf of Mexico

- **Shenandoah** The Company expensed $437 million of exploratory well costs, including $326 million of costs that were suspended as of December 31, 2016. The Shenandoah-6 appraisal well and subsequent sidetrack, which completed appraisal activities in April 2017 and did not encounter oil in the eastern portion of the field. Given the results of this well and the commodity-price environment at the time, the Company suspended further appraisal activities. In 2018, the Company relinquished its ownership interest in Shenandoah.
- **Phobos** The Company expensed $215 million of exploratory well costs, including $99 million of costs that were suspended as of December 31, 2016, in the third quarter of 2017 related to wells at the Phobos project. These wells found insufficient quantities of oil pay to justify development in the current price environment.
- **Warrior** The Company expensed $108 million of exploratory well costs in the third quarter of 2017 related to the northern appraisal well and sidetrack at the Warrior project. These wells found insufficient quantities of oil pay to justify development of the northern portion of the field in the current price environment. Evaluation of tie-back opportunities in the southern portion of the field is ongoing.

Colombia

- The Company expensed $243 million of exploratory well costs, including $109 million of costs that were suspended as of December 31, 2016, related to wells in the Grand Fuerte area in Colombia due to insufficient progress on contractual and fiscal reforms needed for deepwater gas development. All remaining leases are contractually in good standing.

Côte d'Ivoire

- The Company expensed $329 million of exploratory well costs, including $237 million of costs that were suspended as of December 31, 2016, in Côte d'Ivoire. During 2017, the Company had unsuccessful drilling activities in the south channel of the Paon prospect and in Block CI-527 and after further evaluation of the well results Anadarko withdrew from all exploration blocks in Côte d'Ivoire. The Company expects to complete the withdrawal from its remaining appraisal block in 2019.

7. Suspended Exploratory Well Costs (Continued)

2016 During the year ended December 31, 2016, suspended exploratory well costs charged to exploration expense primarily related to the following:

Gulf of Mexico

– The Company expensed $231 million of suspended exploratory well costs in the Gulf of Mexico primarily related to the Yeti project, as the Company did not expect to have exploration activities on this prospect in the foreseeable future, and a Shenandoah well that was expensed, as it was no longer reasonably possible that the wellbore could be used in the development of the project.

Mozambique

– The Company expensed $92 million of suspended exploratory well costs in Mozambique. The Tubarão-Tigre discovery wells were expensed based on the outlook for development viability, the commodity market conditions, and the complexity introduced by the depth and characteristics of the reservoir. The Orca-4 well was expensed after additional reservoir analysis and the determination that the well was not associated with the first three Orca wells.

The following provides an aging of suspended well balances at December 31:

millions	2018	2017	2016
Exploratory well costs capitalized for a period of one year or less	$ 152	$ 201	$ 460
Exploratory well costs capitalized for a period greater than one year	292	324	770
Balance at December 31	$ 444	$ 525	$ 1,230

7. Suspended Exploratory Well Costs (Continued)

The following summarizes a further aging by geographic area of those exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling at December 31, 2018:

millions except projects	Number of Projects	Total	2017	2016	2015 and prior
U.S. onshore	1	$ 2	$ —	$ —	$ 2
U.S. offshore	1	73	(1)	74	—
International	3	217	11	14	192
	5	$ 292	$ 10	$ 88	$ 194

For exploratory wells, drilling costs are capitalized, or "suspended," on the balance sheet when the well has found a sufficient quantity of reserves to justify its completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. Suspended exploratory well costs capitalized for a period greater than one year after completion of drilling at December 31, 2018, primarily related to the Gulf of Mexico, Ghana, and Mozambique.

Gulf of Mexico Exploratory well costs are primarily related to the Warrior discovery and have been suspended pending further appraisal activities for potential tieback to the existing infrastructure, including analysis of well results and geologic and geophysical studies, and project sanctioning.

Ghana Exploratory well costs are related to the Mahogany East and Teak prospects, which are included in the Greater Jubilee Full Field Development Plan approved by the Ghanaian government in October 2017. Well costs remain suspended pending further technical analysis and future drilling results.

Mozambique Exploratory well costs are related to the initial two-train Golfinho/Atum project. In 2018, the Company obtained government approval of the Development Plan, advanced major infrastructure projects, advanced onshore and offshore construction and installation contracts, executed long-term LNG sales and purchase agreements (SPAs), and launched project financing. During 2018 and subsequent to year end, additional SPAs were executed, increasing the contracted volume to more than 7.5 MTPA. Execution of SPAs representing 2.0 MTPA of additional contracted volume is anticipated prior to FID. The Company is working to finalize project finance arrangements with lenders and secure all partner and government-related approvals required to proceed with making a final investment decision in the first half of 2019.

If additional information becomes available that raises substantial doubt as to the economic or operational viability of any of these projects, the associated costs will be expensed at that time.

8. Goodwill and Other Intangible Assets

Goodwill At December 31, 2018, the Company had $4.8 billion of goodwill allocated to the following reporting segments: $4.3 billion to Exploration and Production, $416 million to WES Midstream, and $30 million to Other Midstream. The Company's 2018 annual qualitative impairment assessment of goodwill indicated no impairment. Qualitative factors were also assessed in the fourth quarter of 2018 to review any changes in circumstances subsequent to the annual test, including changes in commodity prices. This assessment also indicated no impairment.

Other Intangible Assets Intangible assets and associated amortization expense were as follows at December 31:

millions		**2018**		2017
Gross carrying amount	**$**	**980**	$	1,013
Accumulated amortization		**(139)**		(140)
Net carrying amount	**$**	**841**	$	873
Amortization expense	**$**	**32**	$	31

Intangible assets are primarily related to customer contracts associated with WES's 2014 acquisition of Delaware basin processing infrastructure. These contracts are being amortized over 30 years. The annual aggregate amortization expense for intangible assets is expected to be $32 million for each of the next five years.

9. Equity-Method Investments

In 2007, Anadarko contributed certain of its oil and gas properties and gathering and processing assets, with an aggregate fair value of $2.9 billion at the time of the contribution, to newly formed unconsolidated entities in exchange for noncontrolling mandatorily redeemable LIBOR-based preferred interests in those entities. The common equity of the investee entities is 95% owned by third parties that also maintain control over the assets. Subsequent to their formation, the investee entities loaned Anadarko an aggregate of $2.9 billion, each with a 35-year term. The Company accounts for its investment in these entities using the equity method of accounting. The carrying amount of these investments was $2.8 billion and the carrying amount of notes payable to affiliates was $2.9 billion at December 31, 2018. Anadarko's noncontrolling interest may be redeemed beginning in 2022 by Anadarko or the owner of the controlling interest. Anadarko's interest is mandatorily redeemable in 2037. Anadarko has legal right of setoff and intends to net settle its obligations under each of the notes payable to the investees with the distributable value of its interest in the corresponding investee. Accordingly, the investment for each entity and the related obligation are presented net on the Company's Consolidated Balance Sheets. Other long-term liabilities—other included $41 million at December 31, 2018, and $46 million at December 31, 2017, and other assets included $4 million at December 31, 2018 and $4 million at December 31, 2017, related to these investments.

Interest on the notes issued by Anadarko is variable, and is equivalent to LIBOR plus a spread that fluctuates with Anadarko's credit rating. The applicable interest rate was 3.79% at December 31, 2018, and 2.59% at December 31, 2017. The note payable agreement contains a quarterly covenant that provides for a maximum Anadarko debt-to-capital ratio of 67% (excluding the effect of non-cash write-downs). Anadarko was in compliance with this covenant at December 31, 2018. Other (income) expense, net includes interest expense on the notes payable of $91 million in 2018, $64 million in 2017, and $49 million in 2016, and equity (earnings) losses from Anadarko's investments in the investee entities of$(87) million in 2018, $(56) million in 2017, and $(33) million in 2016.

10. Current Liabilities

Accounts Payable Accounts payable, trade included liabilities of $180 million at December 31, 2018, and $219 million at December 31, 2017, representing the amount by which checks issued but not presented to the Company's banks for collection exceeded balances in applicable bank accounts. Changes in these liabilities are classified as cash flows from financing activities.

Other Current Liabilities The following summarizes the Company's other current liabilities at December 31:

millions	**2018**	2017
Accrued income taxes	**$ 167**	$ 71
Interest payable	**267**	246
Production, property, and other taxes payable	**309**	216
Accrued employee benefits	**319**	210
Derivatives	**89**	384
Other	**144**	183
Total other current liabilities	**$ 1,295**	$ 1,310

11. Derivative Instruments

Objective and Strategy The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Futures, swaps, and options are used to manage exposure to commodity-price risk inherent in the Company's oil and natural-gas production and natural-gas processing operations (Oil and Natural-Gas Production/Processing Derivative Activities). Futures contracts and commodity-price swap agreements are used to fix the price of expected future oil and natural-gas sales at major industry trading locations, such as Cushing, Oklahoma or Sullom Voe, Scotland for oil and Henry Hub, Louisiana for natural gas. Basis swaps are periodically used to fix or float the price differential between product prices at one market location versus another. Options are used to establish a floor price, a ceiling price, or a floor and a ceiling price (collar) for expected future oil and natural-gas sales. Derivative instruments are also used to manage commodity-price risk inherent in customer price requirements and to fix margins on the future sale of natural gas and NGLs from the Company's leased storage facilities.

Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio is subject to changes in interest rates.

The Company does not apply hedge accounting to any of its currently outstanding derivative instruments. As a result, gains and losses associated with derivative instruments are recognized currently in earnings. Net derivative losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and are reclassified to earnings as the transactions to which the derivatives relate are recognized in earnings. See *Note 22—Accumulated Other Comprehensive Income (Loss)*.

11. Derivative Instruments (Continued)

Oil and Natural-Gas Production/Processing Derivative Activities The oil prices listed below are a combination of NYMEX WTI and Intercontinental Exchange, Inc. (ICE) Brent Blend prices. The Company had no natural-gas production/processing derivatives at December 31, 2018. The following is a summary of the Company's oil derivative instruments at December 31, 2018:

	2019 Settlement
Oil	
Three-Way Collars (MBbls/d)	87
Average price per barrel	
Ceiling sold price (call)	$ 72.98
Floor purchased price (put)	$ 56.72
Floor sold price (put)	$ 46.72

A three-way collar is a combination of three options: a sold call, a purchased put, and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volume. The purchased put establishes the minimum price that the Company will receive for the contracted volume unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price (e.g., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

Anadarko Interest-Rate Derivatives (Excluding WES) Anadarko has outstanding interest-rate swap contracts to manage interest-rate risk associated with anticipated debt issuances. The Company has locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month LIBOR.

In August 2018, the Company amended an interest-rate swap with a notional principal amount of $200 million, extending the mandatory termination date from 2018 to 2023 in exchange for a cash payment of approximately $10 million.

At December 31, 2018, the Company had outstanding interest-rate swaps with a notional amount of $1.6 billion due prior to or in September 2023 that manage interest-rate risk associated with potential future debt issuances. Depending on market conditions, liability-management actions, or other factors, the Company may enter into offsetting interest-rate swap positions or settle or amend certain or all of the currently outstanding interest-rate swaps. The Company had the following outstanding interest-rate swaps at December 31, 2018:

millions except percentages Notional Principal Amount	Reference Period	Mandatory Termination Date	Weighted-Average Interest Rate
$ 550	September 2016 - 2046	September 2020	6.418%
$ 250	September 2016 - 2046	September 2022	6.809%
$ 100	September 2017 - 2047	September 2020	6.891%
$ 250	September 2017 - 2047	September 2021	6.570%
$ 450	September 2017 - 2047	September 2023	6.445%

Derivative settlements and collateralization are classified as cash flows from operating activities unless the derivatives contain an other-than-insignificant financing element, in which case the settlements and collateralization are classified as cash flows from financing activities. As a result of prior extensions of reference-period start dates without settlement of the related interest-rate derivative obligations, the interest-rate derivatives in Anadarko's portfolio contain an other-than-insignificant financing element, and therefore, any settlements, collateralization, or cash payments for amendments related to these extended interest-rate derivatives are classified as cash flows from financing activities. Net cash payments related to settlements and amendments of interest-rate swap agreements were $92 million in 2018 and $112 million in 2017.

11. Derivative Instruments (Continued)

WES Interest-Rate Derivatives In December 2018, WES entered into interest-rate swap agreements with an aggregate notional amount of $750 million to manage interest-rate risk associated with anticipated 2019 debt issuances. WES has locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month LIBOR. Depending on market conditions, liability management actions, or other factors, WES may settle or amend certain or all of the currently outstanding interest-rate swaps. The following interest-rate swaps were outstanding at December 31, 2018:

millions except percentages			Mandatory	Fixed
Notional Principal Amount		**Reference Period**	**Termination Date**	**Interest Rate**
$	250	December 2019 - 2024	December 2019	2.730%
$	250	December 2019 - 2029	December 2019	2.856%
$	250	December 2019 - 2049	December 2019	2.905%

Effect of Derivative Instruments—Balance Sheet The following summarizes the fair value of the Company's derivative instruments at December 31:

millions	Gross Derivative Assets		Gross Derivative Liabilities	
Balance Sheet Classification	**2018**	2017	**2018**	2017
Commodity derivatives - Anadarko [(1)]				
Other current assets	**$ 300**	$ 7	**$ (126)**	$ (1)
Other assets	**—**	2	**—**	—
Other current liabilities	**1**	45	**(6)**	(206)
Other liabilities	**—**	—	**—**	(2)
	301	54	**(132)**	(209)
Interest-rate derivatives - Anadarko [(1)]				
Other current assets	**22**	14	**—**	—
Other assets	**34**	40	**—**	—
Other current liabilities	**—**	—	**(82)**	(236)
Other liabilities	**—**	—	**(1,156)**	(1,183)
	56	54	**(1,238)**	(1,419)
Interest-rate derivatives - WES				
Other current liabilities	**—**	—	**(8)**	—
Total derivatives	**$ 357**	$ 108	**$ (1,378)**	$ (1,628)

(1) Excludes amounts related to WES interest-rate swap agreements.

11. Derivative Instruments (Continued)

Effect of Derivative Instruments—Statement of Income The following summarizes gains and losses related to derivative instruments:

millions **Classification of (Gain) Loss Recognized**	**2018**	2017	2016
Commodity derivatives - Anadarko [(1)]			
Gathering, processing, and marketing sales	**$ 8**	$ (4)	$ 6
(Gains) losses on derivatives, net	**213**	3	147
Interest-rate derivatives - Anadarko [(1)]			
(Gains) losses on derivatives, net	**(91)**	132	139
Interest-rate derivatives - WES			
(Gains) losses on derivatives, net	**8**	—	—
Total (gains) losses on derivatives, net	**$ 138**	$ 131	$ 292

(1) Excludes amounts related to WES interest-rate swap agreements.

Credit-Risk Considerations The financial integrity of exchange-traded contracts, which are subject to nominal credit risk, is assured by NYMEX or ICE through systems of financial safeguards and transaction guarantees. Over-the-counter traded swaps, options, and futures contracts expose the Company to counterparty credit risk. The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines, and assesses the impact on the fair value of its counterparties' creditworthiness. The Company has the ability to require cash collateral or letters of credit to mitigate its credit-risk exposure.

The Company has netting agreements with financial institutions that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities and routinely exercises its contractual right to offset gains and losses when settling with derivative counterparties. In addition, the Company has setoff agreements with certain financial institutions that may be exercised in the event of default and provide for contract termination and net settlement across derivative types.

The Company's derivative instruments are subject to individually negotiated credit provisions that may require collateral of cash or letters of credit depending on the derivative's portfolio valuation versus negotiated credit thresholds. These credit thresholds generally require full or partial collateralization of the Company's obligations depending on certain credit-risk-related provisions, such as the Company's credit rating from S&P and Moody's. As of December 31, 2018, the Company's long-term debt was rated investment grade (BBB) by both S&P and Fitch and below investment grade (Ba1) by Moody's. Subsequent to year end, Moody's changed its outlook with respect to its rating from stable to positive. The Company may be required to post additional collateral with respect to its derivative instruments if its credit ratings decline below current levels or if the liability associated with any such derivative instrument increases above the credit threshold. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.1 billion (net of $66 million of collateral) at December 31, 2018, and $1.4 billion (net of $170 million of collateral) at December 31, 2017.

11. Derivative Instruments (Continued)

Fair Value Fair value of futures contracts is based on unadjusted quoted prices in active markets for identical assets or liabilities, which represent Level 1 inputs. Valuations of physical-delivery purchase and sale agreements, over-the-counter financial swaps, and commodity option collars are based on similar transactions observable in active markets and industry-standard models that primarily rely on market-observable inputs. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs, because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. Inputs used to estimate the fair value of swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and, for Black-Scholes option valuations, discount factors and implied market volatility.

The following summarizes the fair value of the Company's derivative assets and liabilities, by input level within the fair-value hierarchy:

millions	Level 1	Level 2	Level 3	Netting [(1)]	Collateral	Total
December 31, 2018						
Assets						
Anadarko [(2)]						
Commodity derivatives	$ 1	$ 300	$ —	$ (127)	$ —	$ 174
Interest-rate derivatives	—	56	—	—	—	56
Total derivative assets	$ 1	$ 356	$ —	$ (127)	$ —	$ 230
Liabilities						
Anadarko [(2)]						
Commodity derivatives	$ (2)	$ (130)	$ —	$ 127	$ 2	$ (3)
Interest-rate derivatives	—	(1,238)	—	—	66	(1,172)
WES						
Interest-rate derivatives	—	(8)	—	—	—	(8)
Total derivative liabilities	$ (2)	$ (1,376)	$ —	$ 127	$ 68	$ (1,183)
December 31, 2017						
Assets						
Anadarko [(2)]						
Commodity derivatives	$ 1	$ 53	$ —	$ (46)	$ (1)	$ 7
Interest-rate derivatives	—	54	—	—	—	54
Total derivative assets	$ 1	$ 107	$ —	$ (46)	$ (1)	$ 61
Liabilities						
Anadarko [(2)]						
Commodity derivatives	$ (1)	$ (208)	$ —	$ 46	$ 3	$ (160)
Interest-rate derivatives	—	(1,419)	—	—	170	(1,249)
Total derivative liabilities	$ (1)	$ (1,627)	$ —	$ 46	$ 173	$ (1,409)

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle.

(2) Excludes amounts related to WES interest-rate swap agreements.

12. Tangible Equity Units

In June 2015, the Company issued 9.2 million 7.50% TEUs at a stated amount of $50.00 per TEU and raised net proceeds of $445 million. Each TEU was comprised of a prepaid equity purchase contract for common units of WGP and a senior amortizing note. The prepaid equity purchase contract was considered a freestanding financial instrument, indexed to WGP common units, and met the conditions for equity classification.

Equity Component On June 7, 2018, the mandatory settlement date, Anadarko settled 9.2 million outstanding TEUs in exchange for approximately 8.2 million WGP common units based on the determined final settlement rate of 0.8921 WGP common units per outstanding TEU. See settlement of tangible equity units in the Company's Consolidated Statement of Equity.

Debt Component Each senior amortizing note had an initial principal amount of $10.95 and bore interest at 1.50% per year. The final installment payment of $9 million was made on June 7, 2018. For activity related to the senior amortizing notes, see *Note 13—Debt and Interest Expense*.

13. Debt and Interest Expense

Debt Activity The following summarizes the Company's borrowing activity, after eliminating the effect of intercompany transactions:

	Carrying Value				
millions	WES	WGP [1]	Anadarko [2]	Anadarko Consolidated	Description
Balance at December 31, 2016	$ 3,091	$ 28	$ 11,959	$ 15,078	
Borrowings					
	370	—	—	370	WES RCF
Repayments					
	—	—	(6)	(6)	7.000% Debentures due 2027
	—	—	(3)	(3)	6.625% Debentures due 2028
	—	—	(1)	(1)	7.950% Debentures due 2029
	—	—	(34)	(34)	TEUs - senior amortizing notes
Other, net	4	—	50	54	Amortization of discounts, premiums, and debt issuance costs
Balance at December 31, 2017	$ 3,465	$ 28	$ 11,965	$ 15,458	
Issuances					
	394	**—**	**—**	**394**	WES 4.500% Senior Notes due 2028
	687	**—**	**—**	**687**	WES 5.300% Senior Notes due 2048
	396	**—**	**—**	**396**	WES 4.750% Senior Notes due 2028
	342	**—**	**—**	**342**	WES 5.500% Senior Notes due 2048
Borrowings					
	540	**—**	**—**	**540**	WES RCF
Repayments					
	—	**—**	**(114)**	**(114)**	7.050% Debentures due 2018
	—	**—**	**(123)**	**(123)**	4.850% Senior Notes due 2021
	—	**—**	**(375)**	**(375)**	3.450% Senior Notes due 2024
	—	**—**	**(35)**	**(35)**	Zero Coupon Notes due 2036
	(350)	**—**	**—**	**(350)**	WES 2.600% Senior Notes due 2018
	(690)	**—**	**—**	**(690)**	WES RCF
	—	**—**	**(17)**	**(17)**	TEUs - senior amortizing notes
Other, net	**3**	**—**	**53**	**56**	Amortization of discounts, premiums, and debt issuance costs
Balance at December 31, 2018	**$ 4,787**	**$ 28**	**$ 11,354**	**$ 16,169**	

[1] Excludes WES.
[2] Excludes WES and WGP.

13. Debt and Interest Expense (Continued)

Debt See Note 9—Equity-Method Investments for disclosure regarding Anadarko's notes payable related to its ownership of certain noncontrolling mandatorily redeemable interests that are not included in the Company's reported debt balance and do not affect consolidated interest expense. The following summarizes the Company's outstanding debt, including capital lease obligations, after eliminating the effect of intercompany transactions:

	December 31, 2018			
millions	WES	WGP [1]	Anadarko [2]	Anadarko Consolidated
6.950% Senior Notes due 2019	$ —	$ —	$ 300	$ 300
8.700% Senior Notes due 2019	—	—	600	600
4.850% Senior Notes due 2021	—	—	677	677
WES 5.375% Senior Notes due 2021	500	—	—	500
WES 4.000% Senior Notes due 2022	670	—	—	670
3.450% Senior Notes due 2024	—	—	248	248
6.950% Senior Notes due 2024	—	—	650	650
WES 3.950% Senior Notes due 2025	500	—	—	500
WES 4.650% Senior Notes due 2026	500	—	—	500
5.550% Senior Notes due 2026	—	—	1,100	1,100
7.500% Debentures due 2026	—	—	112	112
7.000% Debentures due 2027	—	—	48	48
7.125% Debentures due 2027	—	—	150	150
WES 4.500% Notes due 2028	400	—	—	400
WES 4.750% Notes due 2028	400	—	—	400
6.625% Debentures due 2028	—	—	14	14
7.150% Debentures due 2028	—	—	235	235
7.200% Debentures due 2029	—	—	135	135
7.950% Debentures due 2029	—	—	116	116
7.500% Senior Notes due 2031	—	—	900	900
7.875% Senior Notes due 2031	—	—	500	500
Zero Coupon Senior Notes due 2036	—	—	2,270	2,270
6.450% Senior Notes due 2036	—	—	1,750	1,750
7.950% Senior Notes due 2039	—	—	325	325
6.200% Senior Notes due 2040	—	—	750	750
4.500% Senior Notes due 2044	—	—	625	625
WES 5.450% Senior Notes due 2044	600	—	—	600
6.600% Senior Notes due 2046	—	—	1,100	1,100
WES 5.300% Notes due 2048	700	—	—	700
WES 5.500% Notes due 2048	350	—	—	350
7.730% Debentures due 2096	—	—	61	61
7.500% Debentures due 2096	—	—	78	78
7.250% Debentures due 2096	—	—	49	49
WES RCF	220	—	—	220
WGP RCF	—	28	—	28
Total borrowings at face value	$ 4,840	$ 28	$ 12,793	$ 17,661
Net unamortized discounts, premiums, and debt issuance costs [3]	(53)	—	(1,439)	(1,492)
Total borrowings [4]	4,787	28	11,354	16,169
Capital lease obligations	—	—	248	248
Less short-term debt	—	28	919	947
Total long-term debt	$ 4,787	$ —	$ 10,683	$ 15,470

13. Debt and Interest Expense (Continued)

	December 31, 2017			
millions	WES	WGP [1]	Anadarko [2]	Anadarko Consolidated
7.050% Debentures due 2018	$ —	$ —	$ 114	$ 114
TEUs - senior amortizing notes due 2018	—	—	17	17
WES 2.600% Senior Notes due 2018	350	—	—	350
6.950% Senior Notes due 2019	—	—	300	300
8.700% Senior Notes due 2019	—	—	600	600
4.850% Senior Notes due 2021	—	—	800	800
WES 5.375% Senior Notes due 2021	500	—	—	500
WES 4.000% Senior Notes due 2022	670	—	—	670
3.450% Senior Notes due 2024	—	—	625	625
6.950% Senior Notes due 2024	—	—	650	650
WES 3.950% Senior Notes due 2025	500	—	—	500
WES 4.650% Senior Notes due 2026	500	—	—	500
5.550% Senior Notes due 2026	—	—	1,100	1,100
7.500% Debentures due 2026	—	—	112	112
7.000% Debentures due 2027	—	—	48	48
7.125% Debentures due 2027	—	—	150	150
6.625% Debentures due 2028	—	—	14	14
7.150% Debentures due 2028	—	—	235	235
7.200% Debentures due 2029	—	—	135	135
7.950% Debentures due 2029	—	—	116	116
7.500% Senior Notes due 2031	—	—	900	900
7.875% Senior Notes due 2031	—	—	500	500
Zero Coupon Senior Notes due 2036	—	—	2,360	2,360
6.450% Senior Notes due 2036	—	—	1,750	1,750
7.950% Senior Notes due 2039	—	—	325	325
6.200% Senior Notes due 2040	—	—	750	750
4.500% Senior Notes due 2044	—	—	625	625
WES 5.450% Senior Notes due 2044	600	—	—	600
6.600% Senior Notes due 2046	—	—	1,100	1,100
7.730% Debentures due 2096	—	—	61	61
7.500% Debentures due 2096	—	—	78	78
7.250% Debentures due 2096	—	—	49	49
WES RCF	370	—	—	370
WGP RCF	—	28	—	28
Total borrowings at face value	$ 3,490	$ 28	$ 13,514	$ 17,032
Net unamortized discounts, premiums, and debt issuance costs [3]	(25)	—	(1,549)	(1,574)
Total borrowings [4]	3,465	28	11,965	15,458
Capital lease obligations	—	—	231	231
Less short-term debt	—	—	142	142
Total long-term debt	$ 3,465	$ 28	$ 12,054	$ 15,547

(1) Excludes WES.
(2) Excludes WES and WGP.
(3) Unamortized discounts, premiums, and debt issuance costs are amortized over the term of the related debt. Debt issuance costs related to RCFs are included in other current assets and other assets on the Company's Consolidated Balance Sheets.
(4) The Company's outstanding borrowings, except for borrowings under the WGP RCF, are senior unsecured.

13. Debt and Interest Expense (Continued)

Scheduled Maturities Total principal amount of debt maturities related to borrowings for the five years ending December 31, 2023, excluding the potential repayment of the outstanding Zero Coupons that may be put by the holders to the Company annually, were as follows:

	Principal Amount of Debt Maturities			
millions	**WES**	**WGP** [1]	**Anadarko** [2]	**Anadarko Consolidated**
2019	$ —	$ 28	$ 900	$ 928
2020	—	—	—	—
2021	500	—	677	1,177
2022	670	—	—	670
2023	220	—	—	220

(1) Excludes WES.
(2) Excludes WES and WGP.

Fair Value The Company uses a market approach to determine the fair value of its fixed-rate debt using observable market data, which results in a Level 2 fair-value measurement. The carrying amount of floating-rate debt approximates fair value as the interest rates are variable and reflective of market rates. The estimated fair value of the Company's total borrowings was $16.8 billion at December 31, 2018, and $17.7 billion at December 31, 2017.

13. Debt and Interest Expense (Continued)

Anadarko Debt (Excluding WES and WGP) In December 2018, the Company purchased and retired $377 million of its $625 million 3.450% Senior Notes due 2024 and $123 million of its $800 million 4.850% Senior Notes due 2021 pursuant to a tender offer. The Company recognized a net gain of $7 million for the early retirement of these senior notes. The Company repaid $114 million of 7.050% Debentures at maturity in May 2018.

In a 2006 private offering, Anadarko received $500 million of loan proceeds upon issuing the Zero Coupons. The Zero Coupons mature in 2036 and have an aggregate principal amount due at maturity of approximately $2.3 billion, reflecting a yield to maturity of 5.24%. In December 2018, the Company purchased and retired $36 million of the accreted value of its Zero Coupons due 2036 and recognized a loss of $3 million for the early retirement of these senior notes. This early retirement results in a reduction of $90 million of the $2.4 billion originally due at maturity in 2036. Anadarko's Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value of the outstanding Zero Coupons, which, if put in whole, would be $942 million at the next put date in October 2019. None of the Zero Coupons were put to the Company in October 2018. The accreted value of the outstanding Zero Coupons was $905 million at December 31, 2018. Anadarko's Zero Coupons were classified as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2018, as the Company has the ability and intent to refinance these obligations using long-term debt, should a put be exercised. Principal payments related to the Zero Coupons are reported in financing activities and interest accretion payments related to the Zero Coupons are reported in operating activities on the Company's Consolidated Statement of Cash Flows.

In January 2018, the Company amended its $3.0 billion senior unsecured RCF to extend the maturity date to January 2022 (APC RCF) and amended its $2.0 billion 364-day senior unsecured RCF to extend the maturity date to January 2019 (364-Day Facility). In December 2018, the Company amended its APC RCF to extend the maturity date to January 2023. The 364-Day Facility expired in January 2019.

Borrowings under the APC RCF and the 364-Day Facility (collectively, the Credit Facilities) generally bear interest under one of two rate options, at Anadarko's election, using either LIBOR (or Euro Interbank Offered Rate in the case of borrowings under the APC RCF denominated in Euro) or an alternate base rate, in each case plus an applicable margin ranging from 0.00% to 1.65% for the APC RCF and 0.00% to 1.675% for the 364-Day Facility. The applicable margin will vary depending on Anadarko's credit ratings.

The Credit Facilities contain certain customary affirmative and negative covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65% (excluding the effect of non-cash write-downs), and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. At December 31, 2018, the Company had no outstanding borrowings under the Credit Facilities and was in compliance with all covenants.

In January 2015, the Company initiated a commercial paper program, which allows for a maximum of $3.0 billion of unsecured commercial paper notes. The maturities of the commercial paper notes may vary, but may not exceed 397 days. As a result of Moody's credit rating on Anadarko, the Company's access to the commercial paper market has been limited. The Company has not issued commercial paper notes since the downgrade and had no outstanding borrowings under the commercial paper program at December 31, 2018.

13. Debt and Interest Expense (Continued)

WES and WGP Debt In February 2018, WES amended its RCF to extend the maturity date from February 2020 to February 2023 and expand the borrowing capacity to $1.5 billion (WES RCF). As part of the amendment, the WES RCF is expandable to a maximum of $2.0 billion. In December 2018, WES entered into an amendment to extend the maturity date from February 2023 to February 2024 effective on February 15, 2019 and to expand the borrowing capacity to $2.0 billion, while leaving the $500 million accordion feature unexercised. Expansion of the borrowing capacity is subject to the completion of the WES Merger anticipated in the first quarter of 2019. See *Note 24—Noncontrolling Interests* for additional information related to the WES Merger.

Borrowings under the WES RCF bear interest at LIBOR plus an applicable margin ranging from 0.975% to 1.45% depending on WES's credit rating, or the greatest of (i) rates at a margin above the one-month LIBOR, (ii) the federal funds rate, or (iii) prime rates offered by certain designated banks. During 2018, WES borrowed $540 million under its RCF, which was used for general partnership purposes, and made repayments of $690 million. At December 31, 2018, WES had outstanding borrowings under its RCF of $220 million at an interest rate of 3.74%, outstanding letters of credit of $5 million, available borrowing capacity of $1.3 billion, and was in compliance with all covenants.

In March 2018, WES completed a public offering of $400 million aggregate principal amount of 4.500% Senior Notes due March 2028 and a public offering of $700 million aggregate principal amount of 5.300% Senior Notes due March 2048. Net proceeds from the public offerings were used to repay amounts outstanding under the WES RCF. The remaining net proceeds were used for general partnership purposes, including to fund capital expenditures.

In August 2018, WES completed a public offering of $400 million aggregate principal amount of 4.750% Senior Notes due August 2028 and a public offering of $350 million aggregate principal amount of 5.500% Senior Notes due August 2048. The net proceeds from the public offerings were used to repay the maturing $350 million of 2.600% Senior Notes due August 2018, and amounts outstanding under the WES RCF. The remaining net proceeds were used for general partnership purposes, including to fund capital expenditures.

In December 2018, WES entered into a $2.0 billion 364-day senior unsecured credit agreement (WES 364-Day Facility), the proceeds of which will be used to fund substantially all of the cash portion of the consideration under the WES midstream asset contribution and sale and the payment of related transaction costs. The WES 364-Day Facility will mature on the day prior to the one-year anniversary of the completion of the WES Merger, and will bear interest at LIBOR, plus applicable margins ranging from 1.000% to 1.625%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, or (c) LIBOR plus 1%, in each case as defined in the WES 364-Day Facility and plus applicable margins currently ranging from zero to 0.625%, based upon WES's senior unsecured debt rating. WES is also required to pay a ticking fee of 0.175% on the commitment amount beginning 90 days after the effective date of the credit agreement through the date of funding under the WES 364-Day Facility. The WES 364-Day Facility contains covenants and customary events of default that are substantially similar to the WES RCF. Additionally, funding of the WES 364-Day Facility is conditioned upon the completion of the WES Merger, and net cash proceeds received from future asset sales and debt or equity offerings by WES must be used to repay amounts outstanding under the WES 364-Day Facility. See *Note 24—Noncontrolling Interests* for additional information related to the WES Merger.

During 2016, WGP had a $250 million senior secured RCF that matures in March 2019 and was expandable to $500 million, subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions (WGP RCF). In February 2018, WGP voluntarily reduced the aggregate commitments of the lenders under the WGP RCF from $250 million to $35 million. In December 2018, the WGP RCF was amended to extend the maturity date from March 2019 to the earlier of June 2019 or three business days following the completion of the WES Merger. See *Note 24—Noncontrolling Interests* for additional information related to the WES Merger. Obligations under the WGP RCF are secured by a first priority lien on all of WGP's assets (not including the consolidated assets of WES) as well as all equity interests owned by WGP.

Borrowings under the WGP RCF bear interest at LIBOR (with a floor of 0%), plus applicable margins ranging from 2.00% to 2.75% depending on WGP's consolidated leverage ratio, or at a base rate equal to the greatest of (i) the prime rate, (ii) the federal funds rate plus 0.50%, or (iii) LIBOR plus 1.00%, in each case plus applicable margins ranging from 1.00% to 1.75% based upon WGP's consolidated leverage ratio. At December 31, 2018, WGP had outstanding borrowings of $28 million at an interest rate of 4.53% classified as short-term debt on the Company's Consolidated Balance Sheet, available borrowing capacity of $7 million, and was in compliance with all covenants.

13. Debt and Interest Expense (Continued)

Capital Lease Obligations Construction of a FPSO for the Company's TEN field in Ghana commenced in 2013. The Company recognized an asset and related obligation for its approximate 19% nonoperated participating interest share during the construction period. Upon completion of construction in the third quarter of 2016, the Company reported the asset and related obligation as a capital lease of $225 million for the Company's proportionate share of the fair value of the FPSO. The FPSO lease provides for an initial term of 10 years with annual renewal periods for an additional 10 years, annual purchase options that decrease over time, and no residual value guarantees. The capital lease asset is being depreciated over the estimated proved reserves of the TEN field using the UOP method, with the associated depreciation included in DD&A in the Company's Consolidated Statement of Income. The accumulated depreciation of the FPSO capital lease asset was $72 million at December 31, 2018, and $41 million at December 31, 2017. The capital lease obligation is being accreted to the present value of the minimum lease payments using the effective interest method. The Company made capital lease payments of $46 million in 2018 and $44 million in 2017.

At December 31, 2018, future minimum lease payments related to the Company's capital leases were:

millions		
2019	$	58
2020		50
2021		48
2022		45
2023		43
Thereafter		323
Total future minimum lease payments	$	567
Less portion representing imputed interest		319
Capital lease obligations	$	248

Interest Expense The following summarizes interest expense for the years ended December 31:

millions		**2018**		2017		2016
Debt and other	**$**	**1,028**	$	1,003	$	1,022
Capitalized interest		**(81)**		(71)		(132)
Total interest expense	**$**	**947**	$	932	$	890

14. Income Taxes

The Tax Reform Legislation enacted on December 22, 2017, reduced the U.S. corporate tax rate from 35% to 21%. Upon enactment, the Company recognized a provisional and one-time deferred tax benefit of $1.2 billion, inclusive of a $236 million increase to the Company's valuation allowance on its foreign tax credit carryforwards, due to the remeasurement of its U.S. deferred tax assets and liabilities based on the rate reduction. During 2018, the Company completed the accounting for the income tax effects related to the adoption of the Tax Reform Legislation before the end of the measurement period. The Company revised the provisional amount recorded in 2017 and recognized an additional current tax benefit of $26 million, primarily related to the acceleration of pension deductions into 2017. This benefit was offset by deferred tax expense of $121 million, primarily related to additional valuation allowance on the Company's foreign tax credit carryforwards.

The following summarizes components of income tax expense (benefit) for the years ended December 31:

millions	**2018**	2017	2016
Current			
Federal	**$ 14**	$ 236	$ (140)
State	**(1)**	48	(1)
Foreign	**595**	414	378
Total current tax expense (benefit)	**608**	698	237
Deferred			
Federal	**150**	(2,082)	(1,020)
State	**(26)**	(17)	(148)
Foreign	**1**	(76)	(90)
Total deferred tax expense (benefit)	**125**	(2,175)	(1,258)
Total income tax expense (benefit)	**$ 733**	$ (1,477)	$ (1,021)

14. Income Taxes (Continued)

Total income taxes differed from the amounts computed by applying the U.S. federal statutory income tax rate to income (loss) before income taxes. The following summarizes the sources of these differences for the years ended December 31:

millions except percentages	2018	2017	2016
Income (loss) before income taxes			
Domestic	$ 492	$ (1,322)	$ (3,728)
Foreign	993	(366)	(101)
Total	$ 1,485	$ (1,688)	$ (3,829)
U.S. federal statutory tax rate	21%	35%	35%
Tax computed at the U.S. federal statutory rate	$ 312	$ (591)	$ (1,340)
(Income) loss attributable to noncontrolling interests	(29)	(85)	(92)
Adjustments resulting from			
State income taxes (net of federal income tax benefit)	(18)	25	(108)
U.S. federal tax reform	95	(1,168)	—
Tax impact from foreign operations	181	166	80
Non-deductible Algerian exceptional profits tax	154	110	106
Net changes in uncertain tax positions	(29)	90	90
Dispositions of non-deductible goodwill	—	6	205
Other, net	67	(30)	38
Total income tax expense (benefit)	$ 733	$ (1,477)	$ (1,021)
Effective tax rate	49%	88%	27%

The following summarizes components of total deferred taxes at December 31:

millions	2018	2017
Federal	$ (1,972)	$ (1,758)
State, net of federal	(176)	(200)
Foreign	(255)	(255)
Total deferred taxes [(1)]	$ (2,403)	$ (2,213)

(1) Net deferred tax assets related to Algeria of $34 million in 2018 and $21 million in 2017 are presented in other assets on the Company's Consolidated Balance Sheet.

14. Income Taxes (Continued)

The following summarizes tax effects of temporary differences that give rise to significant portions of the deferred tax assets (liabilities) at December 31:

millions	2018	2017
Deferred tax liabilities		
Oil and gas exploration and development operations	$ (2,403)	$ (2,622)
Midstream and other depreciable properties	(662)	(543)
Mineral operations	(238)	(312)
Other	(134)	(53)
Gross long-term deferred tax liabilities	(3,437)	(3,530)
Deferred tax assets		
Oil and gas exploration and development costs	303	309
Foreign and state net operating loss carryforwards	445	562
U.S. foreign tax credit carryforwards	2,665	2,685
Compensation and benefit plans	301	365
Other	308	420
Gross long-term deferred tax assets	4,022	4,341
Valuation allowances on deferred tax assets not expected to be realized	(2,988)	(3,024)
Net long-term deferred tax assets	1,034	1,317
Total deferred taxes	$ (2,403)	$ (2,213)

The valuation allowance primarily relates to U.S. foreign tax credit carryforwards and foreign and state net operating loss carryforwards, which reduces the Company's net deferred tax asset to an amount that will more likely than not be realized within the carryforward period.

The following summarizes changes in the balance of valuation allowances on deferred tax assets:

millions	2018	2017	2016
Balance at January 1	$ (3,024)	$ (1,755)	$ (1,403)
Changes due to U.S. foreign tax credits	(50)	(1,287)	(477)
Changes due to foreign and state net operating loss carryforwards	72	75	13
Changes due to foreign capitalized costs	14	(57)	112
Balance at December 31	$ (2,988)	$ (3,024)	$ (1,755)

Tax carryforwards available, prior to valuation allowance, at December 31, 2018, were as follows:

millions	Domestic	Foreign	Expiration
Net operating loss—state [(1)]	$ 4,250	$ —	2019-2038
Net operating loss—foreign	$ —	$ 820	2019-Indefinite
Foreign tax credits [(2)]	$ 2,665	$ —	2023-2028
Texas margins tax credit	$ 27	$ —	2026

(1) Net of $711 million uncertain tax position at December 31, 2018.
(2) Net of $378 million uncertain tax position at December 31, 2018.

14. Income Taxes (Continued)

The following summarizes taxes receivable (payable) related to income tax expense (benefit) at December 31:

millions **Balance Sheet Classification**	**2018**	2017
Income taxes receivable		
Accounts receivable—other	**$ 46**	$ 53
Other assets	**51**	101
	97	154
Income taxes (payable)		
Other current liabilities	**(167)**	(71)
Total net income taxes receivable (payable)	**$ (70)**	$ 83

Changes in the balance of unrecognized tax benefits, excluding interest and penalties on uncertain tax positions, were as follows:

	Assets (Liabilities)		
millions	**2018**	2017	2016
Balance at January 1	**$ (1,317)**	$ (1,456)	$ (1,780)
Increases related to prior-year tax positions	**(21)**	(15)	(86)
Decreases related to prior-year tax positions	**48**	214	436
Increases related to current-year tax positions	**—**	(72)	(26)
Settlements	**1**	12	—
Lapse of statute of limitations	**2**	—	—
Balance at December 31	**$ (1,287)**	$ (1,317)	$ (1,456)

The December 31, 2018 balance of unrecognized tax benefits includes potential benefits of $1.24 billion, of which, if recognized, $1.26 billion would affect the effective tax rate on income. Also included are benefits of $43 million related to tax positions for which the ultimate deductibility is highly certain, but the timing of such deductibility is uncertain.

The Company recognized a net tax benefit of $346 million at December 31, 2018 and 2017, related to the deduction of its 2015 settlement payment for the Tronox Adversary Proceeding. This benefit is net of uncertain tax positions of $1.2 billion at December 31, 2018 and 2017, due to uncertainty related to the deductibility of the settlement payment. Due to the deduction of the settlement payment, the Company had a net operating loss carryback for 2015, which resulted in a tentative tax refund of $881 million in 2016. The IRS has audited this position and, in April 2018, issued a final notice of proposed adjustment denying the deductibility of the settlement payment. In September 2018, the Company received a statutory notice of deficiency from the IRS disallowing the net operating loss carryback and rejecting the Company's refund claim. As a result, the Company filed a petition with the U.S. Tax Court to dispute the disallowances in November 2018, and pursuant to standard U.S. Tax Court procedures, the Company is not required to repay the $881 million refund to dispute the IRS's position. Accordingly, the Company has not revised its estimate of the benefit that will ultimately be realized. After the case is tried and briefed in the Tax Court, the court will issue an opinion and then enter a decision. If the Company does not prevail on the issue, the earliest date the Company might be required to repay the refund received, plus interest, would be 91 days after entry of the decision. At such time, the Company would reverse the portion of the $346 million net benefit previously recognized in its consolidated financial statements to the extent necessary to reflect the result of the Tax Court decision. It is reasonably possible the amount of uncertain tax position and/or tax benefit could materially change as the Company asserts its position in the Tax Court proceedings. Although management cannot predict the timing of a final resolution of the Tax Court proceedings, the Company does not anticipate a decision to be entered within the next three years.

14. Income Taxes (Continued)

Income tax audits and the Company's acquisition and divestiture activity have given rise to tax disputes in U.S. and foreign jurisdictions. See Note 18—Contingencies—*Litigation.* Over the next 12 months, it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $70 million to $90 million due to settlements with taxing authorities or lapse in statutes of limitation. With the exception of the deductibility of the Tronox settlement payment discussed above, management believes that the final resolution of outstanding tax audits and litigation will not have a material adverse effect on the Company's consolidated financial condition, results of operations, or cash flows.

The Company accrued approximately $95 million of interest related to uncertain tax positions at December 31, 2018, and $86 million at December 31, 2017. The Company recognized interest and penalties in income tax expense (benefit) of $9 million during 2018 and $55 million during 2017.

Anadarko is subject to audit by tax authorities in the U.S. federal, state, and local tax jurisdictions as well as in various foreign jurisdictions. The following lists the tax years subject to examination by major tax jurisdiction:

	Tax Years
United States	2013-2018
Algeria	2015-2018
Ghana	2015-2018

15. Asset Retirement Obligations

The majority of Anadarko's AROs relate to the plugging of wells and the related abandonment of oil and gas properties. Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives, and the expected timing of settlement. The following summarizes changes in the Company's AROs:

millions	**2018**	2017
Carrying amount at January 1	**$ 2,794**	$ 2,931
Liabilities acquired	**—**	4
Liabilities incurred	**153**	191
Property dispositions	**(99)**	(154)
Liabilities settled	**(274)**	(135)
Accretion expense	**130**	144
Revisions in estimated liabilities	**395**	(187)
Carrying amount at December 31	**$ 3,099**	$ 2,794

16. Conveyance of Future Hard-Minerals Royalty Revenues

During the first quarter of 2016, the Company conveyed a limited-term nonparticipating royalty interest in certain of its coal and trona leases to a third party for $413 million, net of transaction costs. Such conveyance entitles the third party to receive up to $553 million in future royalty revenue over a period of not less than 10 years and not greater than 15 years. Additionally, such third party is entitled to receive 3% of the aggregate royalties earned during the first 10 years between $800 million and $900 million and 4% of the aggregate royalties earned during the first 10 years that exceed $900 million. Generally, such third party relies solely on the royalty payments to recover its investment and, as such, has the risk of the royalties not being sufficient to recover its investment over the term of the conveyance.

Proceeds from this transaction were accounted for as deferred revenues and are included in other current liabilities and other long-term liabilities - other on the Company's Consolidated Balance Sheet. The deferred revenues will be amortized to other revenues, included in gains (losses) on divestitures and other, net, on a unit-of-revenue basis over the term of the agreement. Net proceeds received from the third party were reported in financing activities on the Company's Consolidated Statement of Cash Flows. Semi-annual payments to the third party are scheduled on March 1 and September 1 of each year through March 1, 2026. The specified future amounts that the Company expects to pay and the payment timing are subject to change based upon the actual royalties received by the Company during the term of the conveyance. Royalties received by Anadarko under this agreement are reported in operating activities on the Company's Consolidated Statement of Cash Flows. The semi-annual payments to the third party, up to the aggregate amount of the $413 million net proceeds the Company received for the conveyance in the first quarter of 2016, are reported in financing activities on the Company's Consolidated Statement of Cash Flows. Any additional payments to the third party are reported in operating activities on the Company's Consolidated Statement of Cash Flows to offset the royalties received.

The Company amortized deferred revenues of $36 million in 2018, $38 million in 2017, and $37 million in 2016 as a result of this agreement. The Company made payments for royalties totaling $50 million in 2018 and 2017, and $25 million in 2016. The following summarizes the remaining amounts that the Company expects to pay, prior to the potential 3% to 4% of any excess described above:

millions		
2019	$	52
2020		57
2021		57
2022		58
2023		60
Thereafter		144
Total	$	428

17. Commitments

Operating Leases At December 31, 2018, the Company had $262 million in long-term drilling rig commitments that are accounted for as operating leases. These drilling rig operating leases expire at various dates through 2021. The Company also had $392 million of various commitments under non-cancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors, and aircraft. These operating leases expire at various dates through 2033. Certain of these operating leases contain residual value guarantees at the end of the lease term of $73 million at December 31, 2018. A $5 million liability was accrued for residual value guarantees. In addition, these operating leases include options to purchase the leased property during or at the end of the lease term for the fair market value or other specified amount at that time. The following summarizes future minimum lease payments under operating leases at December 31, 2018:

millions		
2019	$	264
2020		139
2021		57
2022		35
2023		24
Thereafter		135
Total future minimum lease payments	$	654

Anadarko has entered into various agreements to secure drilling rigs necessary to support the execution of its drilling plans over the next several years. The table of future minimum lease payments above includes $209 million related to three offshore drilling vessels, $41 million related to certain contracts for U.S. onshore drilling rigs, and $12 million related to certain contracts for two international drilling rigs. Lease payments associated with the drilling of exploratory wells and development wells net of amounts billed to partners will initially be capitalized as a component of oil and gas properties and either depreciated or impaired in future periods or written off as exploration expense.

Total rent expense, net of sublease income and amounts capitalized, amounted to $74 million in 2018, $55 million in 2017, and $73 million in 2016. Total rent expense included contingent rent expense related to transportation and processing fees of $4 million in 2018, $3 million in 2017, and $6 million in 2016.

Other Commitments Anadarko has various long-term contractual commitments pertaining to oil and natural-gas activities such as work-related commitments for drilling wells, obtaining and processing seismic data, and fulfilling rig commitments. Anadarko also enters into various processing, transportation, storage, and purchase agreements to access markets and provide flexibility to sell its oil, natural gas, and NGLs in certain areas. These agreements expire at various dates through 2033. The following summarizes the gross aggregate future payments under these contracts at December 31, 2018:

millions		
2019	$	1,147
2020		1,155
2021		993
2022		786
2023		646
Thereafter		1,498
Total [(1)]	$	6,225

(1) Excludes purchase commitments for jointly owned fields and facilities for which the Company is not the operator.

18. Contingencies

The Company is a defendant in a number of lawsuits, is involved in governmental proceedings, and is subject to regulatory controls arising in the ordinary course of business, including personal injury claims; property damage claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas exploration, production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. As of December 31, 2018, the Company had $33 million accrued for litigation-related contingencies. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's consolidated financial condition, results of operations, or cash flows.

Litigation In December 2008, Anadarko sold its interest in the Peregrino heavy-oil field offshore Brazil. The Company is currently litigating a dispute with the Brazilian tax authorities regarding the tax rate applicable to the transaction. In December 2008, the Company deposited the amount of tax originally in dispute in a Brazilian real-denominated judicially-controlled Brazilian bank account pending final resolution of the matter. At December 31, 2018, the deposit of $88 million is included in other assets on the Company's Consolidated Balance Sheet.

In July 2009, the lower judicial court ruled in favor of the Brazilian tax authorities. The Company appealed this decision to the Brazilian Regional courts, which upheld the lower court's ruling in favor of the Brazilian tax authorities in December 2011. In April 2012, the Company filed simultaneous appeals to the Brazilian Superior Court and the Brazilian Supreme Court. The appeal to the Brazilian Supreme Court has been stayed pending a decision in the Superior Court appeal.

In August 2013, following a determination by an administrative court in a related matter that the amount of tax in dispute was not calculated properly, the Company filed a petition requesting the withdrawal of a portion of the judicial deposit to the extent it exceeds the amount of tax currently in dispute and any interest on such excess amount. In April 2015, the Company's petition was denied. The Company appealed this decision. The appeal was denied in November 2015.

The Company believes that it will more likely than not prevail in the Brazilian Superior Court and the Brazilian Supreme Court. Therefore, no tax liability has been recorded for Peregrino divestiture-related litigation at December 31, 2018. The Company continues to vigorously defend its tax position in the Brazilian courts.

Guarantees and Indemnifications The Company provides certain indemnifications in relation to asset dispositions. These indemnifications typically relate to disputes, litigation, or tax matters existing at the date of disposition.

Environmental Matters Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. The Company's Consolidated Balance Sheets include liabilities for remediation and reclamation obligations of $109 million at December 31, 2018, and $113 million at December 31, 2017. The current portion of these amounts was included in other current liabilities and the long-term portion of these amounts was included in other long-term liabilities—other on the Company's Consolidated Balance Sheets. The Company continually monitors remediation and reclamation processes and adjusts its liability for these obligations as necessary.

19. Restructuring Charges

In the first quarter of 2016, the Company initiated a workforce reduction program to align the size and composition of its workforce with its expected future operating and capital plans. Employee notifications related to the workforce reduction program were completed by June 30, 2016. The Company recognized $389 million of restructuring charges, comprised of $192 million in G&A and $197 million in Other (income) expense, net, in the Company's Consolidated Statements of Income during the year ended December 31, 2016. All restructuring charges were recognized in 2016, with the exception of $21 million, primarily related to defined-benefit pension settlement expense, which was recognized during 2017 for lump-sum payments to terminated participants.

20. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans

The Company has contributory and non-contributory defined-benefit pension plans, which include both qualified and supplemental plans. The Company also provides certain health care and life insurance benefits for certain retired employees. Retiree health care benefits are funded by contributions from the retiree and, in certain circumstances, contributions from the Company. The Company's retiree life insurance plan is non-contributory.

The following sets forth changes in the benefit obligations and fair value of plan assets for the Company's pension and other postretirement benefit plans for the years ended December 31, 2018 and 2017, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2018 and 2017:

	Pension Benefits		Other Benefits	
millions	**2018**	2017	**2018**	2017
Change in benefit obligation				
Benefit obligation at beginning of year	**$ 2,218**	$ 2,301	**$ 302**	$ 296
Service cost	**90**	87	**1**	2
Interest cost	**77**	84	**11**	12
Actuarial (gain) loss	**(176)**	107	**(23)**	15
Curtailments, settlements, and special termination benefits expense	**15**	23	**—**	(1)
Participant contributions	**—**	—	**7**	5
Benefit payments	**(268)**	(396)	**(25)**	(27)
Foreign-currency exchange-rate changes	**(8)**	12	**—**	—
Benefit obligation at end of year [(1)]	**$ 1,948**	$ 2,218	**$ 273**	$ 302
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,424**	$ 1,340	**$ —**	$ —
Actual return on plan assets	**(57)**	209	**—**	—
Employer contributions	**225**	254	**19**	22
Participant contributions	**—**	—	**7**	5
Benefits paid related to plan settlements	**(212)**	(337)	**(1)**	(3)
Benefit payments, other	**(56)**	(59)	**(25)**	(24)
Foreign-currency exchange-rate changes	**(10)**	17	**—**	—
Fair value of plan assets at end of year	**$ 1,314**	$ 1,424	**$ —**	$ —
Funded status of the plans at end of year	**$ (634)**	$ (794)	**$ (273)**	$ (302)
Amounts recognized on the balance sheet				
Other assets	**$ 63**	$ 58	**$ —**	$ —
Other current liabilities	**(42)**	(16)	**(21)**	(21)
Other long-term liabilities—other	**(655)**	(836)	**(252)**	(281)
Total	**$ (634)**	$ (794)	**$ (273)**	$ (302)
Amounts recognized in accumulated other comprehensive income				
Prior service (credit) cost	**$ 1**	$ —	**$ (2)**	$ (26)
Net actuarial (gain) loss	**399**	501	**(9)**	14
Total	**$ 400**	$ 501	**$ (11)**	$ (12)

(1) The accumulated benefit obligation for all defined-benefit pension plans was $1.6 billion at December 31, 2018 and $1.9 billion at December 31, 2017.

20. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The following summarizes the Company's defined-benefit pension plans with accumulated benefit obligations in excess of plan assets for the years ended December 31:

millions	2018	2017
Projected benefit obligation	$ 1,828	$ 2,079
Accumulated benefit obligation	1,527	1,749
Fair value of plan assets	1,131	1,227

The following summarizes the Company's pension and other postretirement benefit cost for the years ended December 31:

	Pension Benefits			Other Benefits		
millions	2018	2017	2016	2018	2017	2016
Components of net periodic benefit cost						
Service cost	$ 90	$ 87	$ 99	$ 1	$ 2	$ 3
Interest cost	77	84	95	11	12	12
Expected (return) loss on plan assets	(83)	(84)	(97)	—	—	—
Amortization of net actuarial (gain) loss	25	25	42	—	—	—
Amortization of net prior service (credit) cost	—	(1)	—	(24)	(24)	(25)
Settlement expense [(1)]	49	91	146	—	—	—
Termination benefits expense [(1)]	7	4	44	—	—	—
Curtailment expense [(1)]	(1)	—	8	—	—	—
Net periodic benefit cost [(2)]	$ 164	$ 206	$ 337	$ (12)	$ (10)	$ (10)

(1) Settlement expense, termination benefits expense, and curtailment expense for 2016 relate to the workforce reduction program initiated in the first quarter of 2016. See Note 19—Restructuring Charges.

(2) The service cost component of net periodic benefit cost is included in G&A; oil and gas operating expense; gathering, processing, and marketing expense; and exploration expense, and all other components of net periodic benefit cost are included in other (income) expense on the Company's Consolidated Statements of Income.

The following summarizes the amounts recognized in other comprehensive income (before tax benefit) for the years ended December 31:

	Pension Benefits			Other Benefits		
millions	2018	2017	2016	2018	2017	2016
Amounts recognized in other comprehensive income (expense)						
Net actuarial gain (loss)	$ 27	$ —	$ (150)	$ 23	$ (14)	$ (25)
Amortization of net actuarial (gain) loss	74	116	188	—	—	—
Amortization of net prior service (credit) cost	—	(1)	—	(24)	(24)	(34)
Total amounts recognized in other comprehensive income (expense)	$ 101	$ 115	$ 38	$ (1)	$ (38)	$ (59)

The Company amortizes prior service costs (credits) on a straight-line basis over the average remaining service period of employees expected to receive benefits under each plan. Actuarial gains and losses that exceed 10% of the greater of the projected benefit obligation and the market-related value of assets are amortized over the average remaining service period of participating employees expected to receive benefits under each plan. In 2019, an estimated $12 million of net actuarial loss and $2 million of net prior service credit for the pension and other postretirement plans will be amortized from accumulated other comprehensive income into net periodic benefit cost.

20. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement plans include the discount rate, the expected long-term rate of return on plan assets (for funded pension plans), the rate of future compensation increases, and inflation (for postretirement plans). Other assumptions involve demographic factors such as retirement age, mortality, and turnover. The Company evaluates and updates its actuarial assumptions at least annually.

Accumulated and projected benefit obligations are measured as the present value of future cash payments. The Company discounts those cash payments using a discount rate that reflects the weighted average of market-observed yields for select high-quality (AA-rated) fixed-income securities with cash flows that correspond to the expected amounts and timing of benefit payments. The discount-rate assumption used by the Company represents an estimate of the interest rate at which the pension and other postretirement benefit obligations could effectively be settled on the measurement date. Assumed rates of compensation increases for active participants vary by age group, with the resulting weighted-average assumed rate (weighted by the plan-level benefit obligation) provided in the preceding table.

The following summarizes the weighted-average assumptions used by the Company in determining the pension and other postretirement benefit obligations and net periodic benefit cost for the years ended December 31:

	Pension Benefits			Other Benefits		
	2018	2017	2016	**2018**	2017	2016
Benefit obligation assumptions						
Discount rate	**4.30%**	3.62%	4.06%	**4.43%**	3.75%	4.26%
Rates of increase in compensation levels	**5.33%**	5.36%	5.40%	**5.43%**	5.46%	5.48%
Net periodic benefit cost assumptions						
Discount rate	**3.62%**	4.06%	4.62%	**3.75%**	4.26%	5.00%
Long-term rate of return on plan assets	**6.09%**	6.12%	6.77%	**N/A**	N/A	N/A
Rates of increase in compensation levels	**5.36%**	5.40%	5.34%	**5.46%**	5.48%	5.41%

An annual rate of increase indexed to the Consumer Price Index is assumed for purposes of measuring other postretirement benefit obligations. A rate of 1.70% at December 31, 2018, and 2.00% at December 31, 2017 and 2016 was assumed for purposes of measuring other postretirement benefit obligations.

20. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Plan Assets

Investment Policies and Strategies The Company has adopted a balanced, diversified investment strategy, with the intent of maximizing returns without exposure to undue risk. Investments are typically made through investment managers across several investment categories (domestic equity securities, international equity securities, fixed-income securities, real estate, hedge funds, and private equity), with selective exposure to Growth/Value investment styles. Performance for each investment is measured relative to the appropriate index benchmark for its category. Target asset-allocation percentages by major category are 50% equity securities, 25% fixed income, and up to 25% in a combination of other investments such as real estate, hedge funds, and private equity. Investment managers have full discretion as to investment decisions regarding funds under their management to the extent permitted within investment guidelines.

Although investment managers may, at their discretion and within investment guidelines, invest in Anadarko securities, there are no direct investments in Anadarko securities included in plan assets. There may be, however, indirect investments in Anadarko securities through the plans' fund investments. The expected long-term rate of return on plan assets assumption was determined using the year-end 2018 pension investment balances by asset class and expected long-term asset allocation. The expected return for each asset class reflects capital-market projections formulated using a forward-looking building-block approach while also taking into account historical return trends and current market conditions. Equity returns generally reflect long-term expectations of real earnings growth, dividend yield, changes in valuation, and inflation. Returns on fixed-income securities are generally developed based on expected cash returns and risk spread (as appropriate), adjusted for the expected effect that changing yields have on the rate of return. Other asset-class returns are generally derived from their relationship to the equity and fixed-income markets.

Risks and Uncertainties The plan assets include various investment securities that are exposed to various risks such as interest-rate, credit, and market risks. Due to the level of risk associated with certain investment securities, it is possible that changes in the values of investment securities could significantly impact the plan assets.

The plan assets may include securities with contractual cash flows such as asset-backed securities, collateralized mortgage obligations, and commercial mortgage-backed securities, including securities backed by subprime mortgage loans. The value, liquidity, and related income of those securities are sensitive to changes in economic conditions, including real estate values, delinquencies or defaults, or both, and may be adversely affected by shifts in the market's perception of the issuers and changes in interest rates.

20. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Investments in securities traded in active markets are measured based on unadjusted quoted prices, which represent Level 1 inputs. Investments based on Level 2 inputs include direct investments in corporate debt and other fixed-income securities. Investments included as Level 3 inputs are not observable from objective sources.

The fair value of the Company's pension plan assets by asset class and input level within the fair-value hierarchy were as follows:

millions **December 31, 2018**	**Level 1**	**Level 2**	**Level 3** [3]	**Total**
Investments				
Cash and cash equivalents	$ 28	$ —	$ —	$ 28
Fixed income	43	28	—	71
Equity securities	189	—	—	189
Other				
Real estate	—	—	13	13
Other	—	49	—	49
Investments measured at net asset value [1]	—	—	—	964
Total investments [2]	$ 260	$ 77	$ 13	$ 1,314
December 31, 2017				
Investments				
Cash and cash equivalents	$ 1	$ —	$ —	$ 1
Fixed income	55	31	—	86
Equity securities	185	—	—	185
Other				
Real estate	—	—	13	13
Other	—	53	—	53
Investments measured at net asset value [1]	—	—	—	1,086
Total investments [2]	$ 241	$ 84	$ 13	$ 1,424

(1) Certain investments measured at fair value using the net asset value per share (or its equivalent) have not been categorized in the fair value hierarchy. Amounts presented in this table are intended to reconcile the fair value hierarchy to the pension plan assets.
(2) Amount excludes receivables and payables, primarily related to Level 1 investments.
(3) There were no changes in Level 3 investments for the year ended December 31, 2018. The changes in Level 3 investments of $3 million for the year ended December 31, 2017, were attributable to the actual return on plan assets still held at the reporting date.

20. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Cash Contributions and Expected Benefit Payments While reported benefit obligations exceed the fair value of pension and other postretirement plan assets at December 31, 2018, the Company monitors the status of its funded pension plans to ensure that plan funds are sufficient to continue paying benefits. Contributions to funded plans increase plan assets, while contributions to unfunded plans are used to fund current benefit payments.

The following summarizes the Company's contributions for 2018 and expected contributions for 2019:

millions	Expected 2019	2018
Funded pension plans	$ 90	$ 161
Unfunded pension plans	43	64
Unfunded other postretirement plans	22	19
Total	$ 155	$ 244

The following summarizes estimated benefit payments for the next 10 years, including benefit increases due to continuing employee service:

millions	Pension Benefit Payments	Other Benefit Payments
2019	$ 223	$ 22
2020	148	21
2021	150	20
2022	190	20
2023	181	20
2024-2028	839	86

Defined-Contribution Plans The Company maintains several defined-contribution benefit plans, the most significant of which is the Anadarko Employee Savings Plan (ESP). All regular employees of the Company on its U.S. payroll are eligible to participate in the ESP by making elective contributions that are matched by the Company, subject to certain limitations. The Company recognized expense related to these plans of $63 million for 2018 and 2017, and $64 million for 2016.

21. Stockholders' Equity

Common Stock The Company announced a $2.5 billion Share-Repurchase Program in September 2017. During 2018, the Share-Repurchase Program was ultimately expanded to $5.0 billion and extended through mid-year 2020. The Share-Repurchase Program authorizes the repurchase of the Company's common stock in the open market or through private transactions. As of December 31, 2018, the Company had completed $3.75 billion of the Share-Repurchase Program through ASR Agreements and open-market repurchases. These transactions were accounted for as equity transactions, with all of the repurchased shares classified as treasury stock. Additionally, the receipt of these shares reduced the average number of shares of common stock outstanding used to compute both basic and diluted EPS.

During the years ended December 31, 2018 and 2017, the Company entered into and completed ASR Agreements and open-market repurchases as presented below:

millions except per-share amounts **Agreement Date**	**Settlement Date**	**Amount**	**Average Price per Share**	**Initial Shares Delivered**	**Additional Shares Delivered**	**Total Shares Delivered**
ASR Agreements						
October 2017	December 2017	$ 1,000	$ 48.13	15.7	5.1	20.8
January 2018	February 2018	500	58.82	7.0	1.5	8.5
March 2018	June 2018	1,441	65.28	19.1	3.0	22.1
Total ASR Agreements		2,941		41.8	9.6	51.4
Open-market repurchases						
December 2017	December 2017	59	52.00	N/A	N/A	1.1
August 2018	August 2018	250	66.14	N/A	N/A	3.8
September 2018	September 2018	250	63.11	N/A	N/A	3.9
December 2018	December 2018	250	52.34	N/A	N/A	4.8
Total open-market repurchases		809				13.6
Total		$ 3,750	$ 57.69			65.0

Under each ASR Agreement, the Company paid a specific amount in cash and received an initial delivery of shares of the Company's common stock. The initial delivery of shares represented the minimum number of shares to be repurchased under the agreement. The final number of shares delivered upon settlement of each ASR Agreement was determined with reference to the volume-weighted average price of the shares during the term of the agreement less a negotiated settlement price adjustment.

21. Stockholders' Equity (Continued)

In September 2016, the Company completed a public offering of 40.5 million shares of its common stock at a price of $53.23 per share. Net proceeds of $2.16 billion from this equity issuance were primarily used to fund the GOM Acquisition, with the remainder used for general corporate purposes. The following summarizes the changes in the Company's outstanding shares of common stock:

millions	2018	2017	2016
Shares of common stock issued			
Shares at January 1	574	572	528
Exercise of stock options	—	—	1
Issuance of common stock	—	—	41
Issuance of restricted stock	3	2	2
Shares at December 31	577	574	572
Shares of common stock held in treasury			
Shares at January 1	43	21	20
Purchase of treasury stock	43	22	—
Shares received for restricted stock vested and stock options exercised	1	—	1
Shares at December 31	87	43	21
Shares of common stock outstanding at December 31	490	531	551

Earnings Per Share The Company's basic earnings per share (EPS) is computed based on the average number of shares of common stock outstanding for the period and includes the effect of any participating securities and TEUs as appropriate. Diluted EPS includes the effect of the Company's outstanding stock options, restricted stock awards, restricted stock units, and TEUs, if the inclusion of these items is dilutive. All outstanding TEUs were settled in June 2018. See *Note 12—Tangible Equity Units* for additional information.

The following provides a reconciliation between basic and diluted EPS attributable to common stockholders for the years ended December 31:

millions except per-share amounts	2018	2017	2016
Net income (loss)			
Net income (loss) attributable to common stockholders	$ 615	$ (456)	$ (3,071)
Income (loss) effect of TEUs	(4)	(7)	(6)
Less distributions on participating securities	5	1	1
Basic	$ 606	$ (464)	$ (3,078)
Income (loss) effect of TEUs	(1)	(2)	(1)
Diluted	$ 605	$ (466)	$ (3,079)
Shares			
Average number of common shares outstanding—basic	504	548	522
Average number of common shares outstanding—diluted	504	548	522
Excluded due to anti-dilutive effect	9	11	11
Net income (loss) per common share			
Basic	$ 1.20	$ (0.85)	$ (5.90)
Diluted	$ 1.20	$ (0.85)	$ (5.90)
Dividends per common share	$ 1.05	$ 0.20	$ 0.20

22. Accumulated Other Comprehensive Income (Loss)

The following summarizes the after-tax changes in the balances of accumulated other comprehensive income (loss):

millions	Interest-rate Derivatives Previously Subject to Hedge Accounting	Pension and Other Postretirement Plans	Total
Balance at December 31, 2015	$ (42)	$ (341)	$ (383)
Other comprehensive income (loss), before reclassifications	—	(107)	(107)
Reclassifications to Consolidated Statement of Income	5	94	99
Net other comprehensive income (loss)	5	(13)	(8)
Balance at December 31, 2016	$ (37)	$ (354)	$ (391)
Other comprehensive income (loss), before reclassifications	—	(10)	(10)
Reclassifications to Consolidated Statement of Income	2	61	63
Net other comprehensive income (loss)	2	51	53
Balance at December 31, 2017	$ (35)	$ (303)	$ (338)
Other comprehensive income (loss), before reclassifications	**—**	**39**	**39**
Reclassifications to Consolidated Statement of Income	**2**	**35**	**37**
Cumulative effect of accounting change [(1)]	**(7)**	**(66)**	**(73)**
Net other comprehensive income (loss)	**(5)**	**8**	**3**
Balance at December 31, 2018	**$ (40)**	**$ (295)**	**$ (335)**

(1) Beginning January 1, 2018, the Company adopted ASU 2018-02, *Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. See Note 1—Summary of Significant Accounting Policies in the *Notes to Consolidated Financial Statements* for further information.

23. Share-Based Compensation

At December 31, 2018, 20 million shares of the 41 million shares of Anadarko common stock authorized for awards under active share-based compensation plans remained available for future issuance. The Company generally issues new shares to satisfy awards under employee share-based payment plans. The number of shares available is reduced by awards granted. The following summarizes share-based compensation expense for the years ended December 31:

millions	2018	2017	2016
Restricted stock [(1)]	$ 147	$ 145	$ 175
Stock options [(1)]	21	17	20
Other equity-classified awards	1	1	2
Performance-based unit awards [(1)]	19	(13)	38
Pretax share-based compensation expense	$ 188	$ 150	$ 235
Income tax benefit	$ 43	$ 35	$ 86

(1) Includes restructuring charges of $(7) million for performance-based unit awards in 2017 and $31 million for restricted stock, $1 million for stock options, and $7 million for performance-based unit awards in 2016. See *Note 19—Restructuring Charges* for additional information.

Equity-Classified Awards

Restricted Stock Certain employees may be granted restricted stock in the form of restricted stock awards or restricted stock units. Restricted stock is subject to forfeiture restrictions and cannot be sold, transferred, or disposed of during the restriction period. The holders of restricted stock awards have the same rights as a stockholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. A restricted stock unit is equivalent to a restricted stock award except that unit holders do not have the right to vote. Restricted stock vests over service periods ranging from the date of grant generally up to three years and is not considered issued and outstanding for accounting purposes until vested.

Non-employee directors are granted deferred shares, which are also considered restricted stock, that are held in a grantor trust by the Company until payable. Non-employee directors may elect to receive these shares in a lump-sum payment or in annual installments.

The following summarizes the Company's restricted stock activity:

	Shares (millions)	**Weighted-Average Grant-Date Fair Value** (per share)
Non-vested at January 1, 2018	4.69	$ 59.24
Granted	2.72	$ 58.30
Vested	(2.30)	$ 61.19
Forfeited	(0.42)	$ 58.07
Non-vested at December 31, 2018	4.69	$ 57.88

The weighted-average grant-date fair value per share of restricted stock granted was $59.92 during 2017 and $52.03 during 2016. The total fair value of restricted shares vested was $142 million during 2018, $132 million during 2017, and $114 million during 2016, based on the market price at the vesting date. At December 31, 2018, total unrecognized compensation cost related to restricted stock of $172 million is expected to be recognized over a weighted-average remaining service period of 1.5 years.

23. Share-Based Compensation (Continued)

Stock Options Certain employees may be granted nonqualified options to purchase shares of Anadarko common stock with an exercise price equal to, or greater than, the fair market value of Anadarko common stock on the date of grant. These stock options generally vest over three years from the date of grant and terminate at the earlier of the date of exercise or seven years from the date of grant.

The fair value of stock option awards is determined using the Black-Scholes option-pricing model with the following assumptions:

- *Expected life*—Based on historical exercise behavior.
- *Volatility*—Based on an average of historical volatility over the expected life of an option and the 12-month average implied volatility.
- *Risk-free interest rates*—Based on the U.S. Treasury rate over the expected life of an option.
- *Dividend yield*—Based on a 12-month average dividend yield, taking into account the Company's expected dividend policy over the expected life of an option.

The Company used the following weighted-average assumptions to estimate the fair value of stock options granted:

	2018	2017	2016
Weighted-average grant-date fair value	$ 15.36	$ 14.77	$ 15.92
Assumptions			
Expected option life—years	4.8	4.8	4.1
Volatility	33.5%	33.6%	38.2%
Risk-free interest rate	2.9%	2.0%	1.3%
Dividend yield	1.9%	0.4%	0.6%

The following summarizes the Company's stock option activity:

	Shares (millions)	Weighted-Average Exercise Price (per share)	Weighted-Average Remaining Contractual Term (years)	Aggregate Intrinsic Value (millions)
Outstanding at January 1, 2018	6.57	$ 71.44		
Granted	1.19	$ 55.47		
Exercised [(1)]	(0.10)	$ 65.03		
Forfeited or expired	(1.30)	$ 79.55		
Outstanding at December 31, 2018	6.36	$ 67.00	3.92	$ —
Vested or expected to vest at December 31, 2018	6.36	$ 67.00	3.92	$ —
Exercisable at December 31, 2018	4.12	$ 74.19	2.66	$ —

(1) The total intrinsic value of stock options exercised was $1 million during 2018, zero during 2017, and $7 million during 2016, based on the difference between the market price at the exercise date and the exercise price.

Cash received from stock option exercises was $7 million in 2018, zero in 2017, and $30 million in 2016, and the tax benefit from these exercises was zero in both 2018 and 2017, and $2 million in 2016.

At December 31, 2018, total unrecognized compensation cost related to stock options of $25 million is expected to be recognized over a weighted-average remaining service period of 1.6 years.

23. Share-Based Compensation (Continued)

Liability-Classified Awards

Performance-Based Unit Awards Certain officers of the Company were provided Performance Unit Award Agreements with three-year performance periods. The vesting of these units is based on comparing the Company's TSR to the TSR of a predetermined group of peer companies over the specified performance period, with the ultimate value of any vested units determined by the Company's share price at the time of payment, as each performance unit represents the value of one share of the Company's common stock. Following the end of each performance period, the value of the vested performance units, if any, is paid in cash. The Company paid no cash related to vested performance units in 2018, $10 million in 2017, and $6 million in 2016. At December 31, 2018, the Company's liability under Performance Unit Award Agreements was $46 million, with total unrecognized compensation cost related to these awards of $28 million expected to be recognized over a weighted-average remaining performance period of 2.5 years.

24. Noncontrolling Interests

WES is a limited partnership formed by Anadarko to acquire, own, develop, and operate midstream assets. During 2016, WES issued 22 million Series A Preferred units to private investors for net proceeds of $687 million and issued 1.3 million common units to the Company. Proceeds from these issuances were primarily used to acquire interests in Springfield Pipeline LLC from the Company. Pursuant to an agreement between WES and the holders of the Series A Preferred units, 50% of the Series A Preferred units converted into WES common units on a one-for-one basis on March 1, 2017, and all remaining Series A Preferred units converted on May 2, 2017.

WES Class C units issued to Anadarko will convert into WES common units on a one-for-one basis on the conversion date, which was extended in February 2017 from December 31, 2017, to March 1, 2020. The Class C units receive quarterly distributions in the form of additional Class C units until conversion into WES common units. All outstanding WES Class C units will convert into WES common units on a one-for-one basis immediately prior to the closing of the WES Merger, if completed. If the WES Merger is not completed, the conversion will occur on March 1, 2020, unless WES elects to convert such units earlier or Anadarko extends the conversion date. WES distributed 1.1 million Class C units to Anadarko during 2018, and 886 thousand Class C units to Anadarko during 2017, and 946 thousand Class C units to Anadarko during 2016. See *Midstream Asset Sale and WES Merger* below.

WGP is a limited partnership formed by Anadarko to own interests in WES. Anadarko sold 12.5 million WGP common units to the public for net proceeds of $476 million in 2016. In June 2018, Anadarko settled 9.2 million outstanding TEUs, originally issued in 2015, in exchange for approximately 8.2 million WGP common units. For additional disclosure of the TEU effect on noncontrolling interests, see *Note 12—Tangible Equity Units*. At December 31, 2018, Anadarko's ownership interest in WGP consisted of a 77.8% limited partner interest and the entire non-economic general partner interest. The remaining 22.2% limited partner interest in WGP was owned by the public.

At December 31, 2018, WGP's ownership interest in WES consisted of a 29.6% limited partner interest, the entire 1.5% general partner interest, and all of the WES incentive distribution rights. At December 31, 2018, Anadarko also owned a 9.7% limited partner interest in WES through other subsidiaries' ownership of common and Class C units. The remaining 59.2% limited partner interest in WES was owned by the public.

Midstream Asset Sale and WES Merger At the end of 2018, Anadarko announced the planned contribution and sale of substantially all of its midstream assets not owned by WES, which are largely associated with Anadarko's two premier U.S. onshore oil plays in the Delaware and DJ basins, to WES for approximately $4.0 billion, with approximately $2.0 billion of cash proceeds and the balance to be paid in WES common units. Additionally, at the end of 2018, WES announced that a wholly owned subsidiary of WGP will merge with and into WES, with WES continuing as the surviving entity and a subsidiary of WGP, which will result in a simplified midstream structure. Under the terms of the WES Merger, WGP will acquire all of the outstanding publicly held common units of WES and substantially all of the WES common units owned by Anadarko, including the Class C units, which will be converted into WES common units immediately prior to the transaction, in a unit-for-unit, tax-free exchange. WES will survive as a partnership with no publicly traded equity, owned 98% by WGP and 2% by Anadarko. WES will remain the borrower for all existing debt, is expected to remain the borrower for all future debt, and will remain the owner of all operating assets and equity investments. Anadarko will maintain operating control of WGP, with approximately 55.5% pro forma ownership of the combined entity. The WES Merger is expected to close in the first quarter of 2019 concurrently with the asset contribution and sale.

25. Variable Interest Entities

Consolidated VIEs The Company determined that the partners in WGP and WES with equity at risk lack the power, through voting rights or similar rights, to direct the activities that most significantly impact WGP's and WES's economic performance; therefore, WGP and WES are considered VIEs. Anadarko, through its ownership of the general partner interest in WGP, has the power to direct the activities that most significantly affect economic performance and the obligation to absorb losses or the right to receive benefits that could be potentially significant to WGP and WES; therefore, Anadarko is considered the primary beneficiary and consolidates WGP, WES, and all of their consolidated subsidiaries. See Note 24—Noncontrolling Interests for additional information on WGP and WES.

The following tables present selected financial data from the consolidated financial statements of WGP:

millions	2018	2017	2016
Statement of Operations Data			
Total revenues and other	$ 1,990	$ 2,248	$ 1,804
Operating income (loss)	625	704	705
Net income (loss)	449	573	597
Statement of Cash Flows Data			
Net cash provided by (used in) operating activities	$ 1,017	$ 897	$ 913
Net cash provided by (used in) investing activities	(1,460)	(764)	(1,106)
Net cash provided by (used in) financing activities	456	(413)	452

millions	2018	2017
Balance Sheet Data		
Net property, plant, and equipment	$ 6,612	$ 5,731
Total assets	9,239	8,016
Long-term debt	4,787	3,493
Total liabilities	5,734	4,071
Total equity and partners' capital	3,505	3,945

millions	2018	2017	2016
WGP distributions to Anadarko [(1)]	$ 408	$ 368	$ 321
WGP distributions to third parties	494	443	362

(1) WGP distributions to Anadarko are eliminated upon consolidation.

25. Variable Interest Entities (Continued)

Assets and Liabilities of VIEs The assets of WGP, WES, and their subsidiaries cannot be used by Anadarko for general corporate purposes and are included in and disclosed parenthetically on the Company's Consolidated Balance Sheets. The carrying amounts of liabilities related to WGP, WES, and their subsidiaries for which the creditors do not have recourse to other assets of the Company are included in and disclosed parenthetically on the Company's Consolidated Balance Sheets.

All outstanding debt for WES at December 31, 2018 and 2017, including any borrowings under the WES RCF, is recourse to WES's general partner, which in turn has been indemnified in certain circumstances by certain wholly owned subsidiaries of the Company for such liabilities. All outstanding debt for WGP at December 31, 2018 and 2017, including any borrowings under the WGP RCF, is recourse to WGP's general partner, which is a wholly owned subsidiary of the Company. See *Note 13—Debt and Interest Expense* for additional information on WGP and WES long-term debt balances.

VIE Financing WGP's sources of liquidity include borrowings under its RCF and distributions from WES. WES's sources of liquidity include cash and cash equivalents, cash flows generated from operations, interest income from a note receivable from Anadarko as discussed below, borrowings under its RCF, the issuance of additional partnership units, or debt offerings. See *Note 13—Debt and Interest Expense* and *Note 24—Noncontrolling Interests* for additional information on WGP and WES financing activity.

Financial Support Provided to VIEs Concurrent with the closing of its May 2008 IPO, WES loaned the Company $260 million in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%, payable quarterly. The related interest income for WES was $17 million for each of the years ended December 31, 2018, 2017, and 2016. The note receivable and related interest income are eliminated in consolidation.

In March 2015, WES acquired the Company's interest in DBJV. The acquisition was financed using a deferred purchase price obligation that required a cash payment from WES to the Company due on March 31, 2020. In May 2017, WES reached an agreement with the Company to settle this obligation whereby WES made a cash payment to the Company of $37 million, equal to the estimated net present value of the obligation at March 31, 2017.

To reduce WES's exposure to a majority of the commodity-price risk inherent in certain of its contracts, Anadarko had commodity price swap agreements in place with WES during 2018. These commodity price swap agreements expired without renewal on December 31, 2018. WES recorded a capital contribution from Anadarko in its Consolidated Statement of Equity and Partners' Capital for the amount by which the swap price for product purchases exceeds the market price. WES recorded a capital contribution from Anadarko of $52 million for the year ended December 31, 2018, $59 million for the year ended December 31, 2017, and $46 million for the year ended December 31, 2016.

26. Supplemental Cash Flow Information

Additions to properties and equipment as presented within Anadarko's cash flows from investing activities include cash payments for cost of properties, equipment, and facilities. The cost of properties includes the initial capitalization of drilling costs associated with all exploratory wells whether or not they were deemed to have a commercially sufficient quantity of proved reserves.

The following summarizes cash paid (received) for interest and income taxes, as well as non-cash investing and financing activities, for the years ended December 31:

millions	**2018**	2017	2016
Cash paid (received)			
Interest, net of amounts capitalized	**$ 982**	$ 906	$ 856
Income taxes, net of refunds [1]	**51**	64	(882)
Non-cash investing activities			
Fair value of properties and equipment acquired	**$ 22**	$ 640	$ 3
Asset retirement cost additions	**523**	66	298
Accruals of property, plant, and equipment	**822**	824	549
Net liabilities assumed (divested) in acquisitions and divestitures	**(111)**	(158)	723
Non-cash investing and financing activities			
Acquisition contingent consideration	**$ —**	$ —	$ 103
Non-cash financing activities			
Settlement of tangible equity units	**$ 300**	$ —	$ —

(1) Includes $881 million from a tax refund in 2016 related to the income tax benefit associated with the Company's 2015 tax net operating loss carryback.

The following table provides a reconciliation of Cash, Cash Equivalents, Restricted Cash, and Restricted Cash Equivalents as reported in the Consolidated Statement of Cash Flows to the line items within the Consolidated Balance Sheets:

	December 31,	
millions	**2018**	2017
Cash and cash equivalents	**$ 1,295**	$ 4,553
Restricted cash and restricted cash equivalents included in Other Assets	**134**	121
Cash, Cash Equivalents, Restricted Cash, and Restricted Cash Equivalents	**$ 1,429**	$ 4,674

Included in cash and cash equivalents is restricted cash and restricted cash equivalents of $139 million at December 31, 2018, and $255 million at December 31, 2017. Total restricted cash and restricted cash equivalents are primarily associated with certain international joint venture operations, payments of future hard-minerals royalty revenues conveyed, like-kind exchanges of property, and a judicially-controlled account related to a Brazilian tax dispute. See *Note 18—Contingencies* for additional information.

27. Segment Information

Anadarko has three reporting segments: Exploration and Production, WES Midstream, and Other Midstream, which include their respective marketing results. The Company has the option of aggregating its two midstream operating segments, WES Midstream and Other Midstream, into one Midstream reporting segment as both have similar financial and operating characteristics. However, the Company has elected not to aggregate these operating segments in order to provide additional information about its midstream operations.

The Exploration and Production reporting segment is engaged in the exploration, development, production, and sale of oil, natural gas, and NGLs and in advancing its Mozambique LNG project toward an FID. The WES Midstream and Other Midstream reporting segments engage in gathering, compressing, treating, processing, and transporting of natural gas; gathering, stabilizing, and transporting of oil and NGLs; and gathering and disposing of produced water. The WES Midstream segment consists of WES midstream assets, and Other Midstream segment consists of the Company's midstream assets.

To assess the performance of Anadarko's operating segments, the chief operating decision maker analyzes Adjusted EBITDAX. The Company defines Adjusted EBITDAX as income (loss) before income taxes; interest expense; DD&A; exploration expense; gains (losses) on divestitures, net; impairments; total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income (loss) attributable to noncontrolling interests. During the periods presented, items not related to the Company's normal operations included restructuring charges related to the workforce reduction program included in G&A, (gains) losses on early extinguishment of debt, and certain other nonoperating items included in other (income) expense, net.

The Company's definition of Adjusted EBITDAX excludes gains (losses) on divestitures, net and exploration expense as they are not indicators of operating efficiency for a given reporting period. DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives are excluded from Adjusted EBITDAX because these (gains) losses are not considered a measure of asset operating performance. Finally, net income (loss) attributable to noncontrolling interests is excluded from the Company's measure of Adjusted EBITDAX because it represents earnings that are not attributable to the Company's common stockholders.

Management believes Adjusted EBITDAX provides information useful in assessing the Company's operating and financial performance across periods. Adjusted EBITDAX as defined by Anadarko may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures, such as operating income. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes for the years ended December 31:

millions	2018	2017	2016
Income (loss) before income taxes	$ 1,485	$ (1,688)	$ (3,829)
(Gains) losses on divestitures, net	(20)	(674)	757
Exploration expense [(1)]	459	2,535	944
DD&A	4,254	4,279	4,301
Impairments	800	408	227
Interest expense	947	932	890
Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives	(407)	156	559
Restructuring and reorganization-related charges	53	21	389
Other operating expense	—	—	1
(Gains) losses on early extinguishment of debt	(2)	2	155
Certain other nonoperating items	—	—	(58)
Less net income (loss) attributable to noncontrolling interests	137	245	263
Consolidated Adjusted EBITDAX	$ 7,432	$ 5,726	$ 4,073

(1) Includes reorganization-related charges of $20 million for the year ended December 31, 2018.

27. Segment Information (Continued)

The Company's accounting policies for individual segments are the same as those described in the summary of significant accounting policies, with the following exception: certain intersegment commodity contracts may meet the GAAP definition of a derivative instrument, which would be accounted for at fair value under GAAP. However, Anadarko does not recognize any mark-to-market adjustments on such intersegment arrangements. Additionally, intersegment asset transfers are accounted for at historical cost basis and do not give rise to gain or loss recognition.

Information presented below as Other and Intersegment Eliminations includes corporate costs, margin on sales of third-party commodity purchases, deficiency fee expenses, results from hard-minerals royalties, net cash from settlement of commodity derivatives, and net income (loss) attributable to noncontrolling interests. The following summarizes selected financial information for Anadarko's reporting segments:

millions	Exploration & Production	WES Midstream	Other Midstream	Other and Intersegment Eliminations	Total
2018					
Sales revenues	$ 11,401	$ 1,501	$ 117	$ 51	$13,070
Intersegment revenues	81	488	307	(876)	—
Other	(4)	173	41	82	292
Total revenues and other [(1)]	11,478	2,162	465	(743)	13,362
Operating costs and expenses [(2)]	3,917	964	105	257	5,243
Net cash from settlement of commodity derivatives	—	—	—	545	545
Other (income) expense, net [(3)]	—	(8)	—	21	13
Net income (loss) attributable to noncontrolling interests	—	—	—	137	137
Total expenses and other	3,917	956	105	960	5,938
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	—	8	8
Adjusted EBITDAX	$ 7,561	$ 1,206	$ 360	$ (1,695)	$ 7,432
Net properties and equipment	$ 18,184	$ 6,612	$ 1,877	$ 1,942	$28,615
Capital expenditures	$ 4,095	$ 1,178	$ 743	$ 169	$ 6,185
Goodwill	$ 4,343	$ 416	$ 30	$ —	$ 4,789

(1) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.

(2) Operating costs and expenses excludes exploration expense, DD&A, impairments, reorganization-related charges, and certain other operating expenses since these expenses are excluded from Adjusted EBITDAX.

(3) Other (income) expense, net excludes reorganization-related charges since these expenses are excluded from Adjusted EBITDAX.

27. Segment Information (Continued)

millions	Exploration & Production	WES Midstream	Other Midstream	Other and Intersegment Eliminations	Total
2017					
Sales revenues	$ 8,946	$ 1,715	$ 187	$ 121	$10,969
Intersegment revenues	23	523	172	(718)	—
Other	15	153	30	67	265
Total revenues and other [(1)]	8,984	2,391	389	(530)	11,234
Operating costs and expenses [(2)]	3,545	1,330	226	157	5,258
Net cash from settlement of commodity derivatives	—	—	—	(27)	(27)
Other (income) expense, net [(3)]	—	—	—	26	26
Net income (loss) attributable to noncontrolling interests	—	—	—	245	245
Total expenses and other	3,545	1,330	226	401	5,502
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	—	(6)	(6)
Adjusted EBITDAX	$ 5,439	$ 1,061	$ 163	$ (937)	$ 5,726
Net properties and equipment	$ 18,598	$ 5,731	$ 1,140	$ 1,982	$27,451
Capital expenditures	$ 3,779	$ 956	$ 458	$ 107	$ 5,300
Goodwill	$ 4,343	$ 416	$ 30	$ —	$ 4,789
2016					
Sales revenues	$ 7,146	$ 1,055	$ 146	$ 100	$ 8,447
Intersegment revenues	7	712	185	(904)	—
Other	(5)	114	19	51	179
Total revenues and other [(1)]	7,148	1,881	350	(753)	8,626
Operating costs and expenses [(2)]	3,516	853	225	(18)	4,576
Net cash from settlement of commodity derivatives	—	—	—	(265)	(265)
Other (income) expense, net [(3)]	—	—	—	(13)	(13)
Net income (loss) attributable to noncontrolling interests	—	—	—	263	263
Total expenses and other	3,516	853	225	(33)	4,561
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	—	8	8
Adjusted EBITDAX	$ 3,632	$ 1,028	$ 125	$ (712)	$ 4,073
Net properties and equipment	$ 24,251	$ 5,050	$ 885	$ 1,982	$32,168
Capital expenditures	$ 2,688	$ 491	$ 60	$ 75	$ 3,314
Goodwill	$ 4,550	$ 418	$ 32	$ —	$ 5,000

(1) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.
(2) Operating costs and expenses excludes exploration expense, DD&A, impairments, restructuring charges, and certain other operating expenses since these expenses are excluded from Adjusted EBITDAX.
(3) Other (income) expense, net excludes certain other nonoperating items and restructuring charges since these items are excluded from Adjusted EBITDAX.

27. Segment Information (Continued)

The following represents Anadarko's sales revenues (based on the origin of the sales) and net properties and equipment by geographic area:

	Years Ended December 31,		
millions	2018	2017	2016
Sales Revenues			
United States	$ 10,659	$ 9,176	$ 7,049
Algeria	1,596	1,249	1,103
Other International	815	544	295
Total sales revenues	$ 13,070	$ 10,969	$ 8,447

	December 31,	
millions	2018	2017
Net Properties and Equipment		
United States	$ 25,891	$ 24,382
Algeria	808	965
Other International [(1)]	1,916	2,104
Total net properties and equipment	$ 28,615	$ 27,451

(1) Includes $519 million of capitalized costs related to the Mozambique LNG project at December 31, 2018.

Major Customers In 2018, sales to Royal Dutch Shell PLC were $1.4 billion. Sales to BP PLC were $1.3 billion in 2018 and $1.1 billion in 2017. These amounts are included in the Exploration and Production reporting segment. In 2016, there were no sales to customers that exceeded 10% of the Company's total sales revenues.

Quarterly Financial Data

The following summarizes quarterly financial data for 2018 and 2017:

millions except per-share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2018				
Sales revenues	**$ 3,026**	**$ 3,168**	**$ 3,607**	**$ 3,269**
Gains (losses) on divestitures and other, net	**19**	**123**	**90**	**80**
Impairments	**19**	**128**	**172**	**481**
Operating income (loss)	**551**	**819**	**979**	**270**
Net income (loss)	**174**	**17**	**427**	**134**
Net income (loss) attributable to noncontrolling interests	**53**	**(12)**	**64**	**32**
Net income (loss) attributable to common stockholders	**121**	**29**	**363**	**102**
Earnings per share				
Net income (loss) attributable to common stockholders—basic	**$ 0.23**	**$ 0.05**	**$ 0.72**	**$ 0.21**
Net income (loss) attributable to common stockholders—diluted	**$ 0.22**	**$ 0.05**	**$ 0.72**	**$ 0.21**
Average number common shares outstanding—basic	**518**	**504**	**499**	**493**
Average number common shares outstanding—diluted	**519**	**505**	**500**	**494**
2017				
Sales revenues	$ 2,898	$ 2,419	$ 2,610	$ 3,042
Gains (losses) on divestitures and other, net	869	297	(114)	(113)
Impairments	373	10	—	25
Operating income (loss)	(100)	(67)	(749)	351
Net income (loss) [(1)]	(275)	(334)	(641)	1,039
Net income (loss) attributable to noncontrolling interests	43	81	58	63
Net income (loss) attributable to common stockholders	(318)	(415)	(699)	976
Earnings per share				
Net income (loss) attributable to common stockholders—basic	$ (0.58)	$ (0.76)	$ (1.27)	$ 1.80
Net income (loss) attributable to common stockholders—diluted	$ (0.58)	$ (0.76)	$ (1.27)	$ 1.80
Average number common shares outstanding—basic	551	552	553	537
Average number common shares outstanding—diluted	551	552	553	537

(1) Includes a one-time deferred tax benefit of $1.2 billion in the fourth quarter of 2017 related to the Tax Reform Legislation.

The unaudited supplemental information on oil and gas exploration and production activities for 2018, 2017, and 2016 has been presented in accordance with FASB Accounting Standards Codification Topic 932, *Extractive Activities —Oil and Gas,* and the SEC's final rule, *Modernization of Oil and Gas Reporting*. Disclosures by geographic area include the United States and International. For 2018, the International geographic area consisted of proved reserves located in Algeria and Ghana.

Oil and Gas Reserves

The following reserves disclosures reflect estimates of proved reserves, proved developed reserves, and PUDs, net of third-party royalty interests, of oil, natural gas, and NGLs owned at each year end and changes in proved reserves during each of the last three years. Oil and NGL volumes are presented in MMBbls and natural-gas volume is presented in Bcf at a pressure base of 14.73 pounds per square inch. Total volume is presented in MMBOE. For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserves volume.

Reserves for international locations are calculated in accordance with the terms of governing agreements. The international reserves include estimated quantities allocated to Anadarko for recovery of costs and income taxes and Anadarko's net equity share after recovery of such costs.

The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. The results of infill drilling are treated as positive revisions due to increases to expected recovery. Other revisions are due to changes in, among other things, development plans, reservoir performance, commodity prices, economic conditions, and governmental restrictions.

The prices below were used to compute the information presented in the following tables and are adjusted only for fixed and determinable amounts under provisions in existing contracts:

	Oil per Bbl	Natural Gas per MMBtu	NGLs per Bbl
December 31, 2018	**$ 65.56**	**$ 3.10**	**$ 37.68**
December 31, 2017	$ 51.34	$ 2.98	$ 31.83
December 31, 2016	$ 42.75	$ 2.48	$ 19.74

Oil and Gas Reserves (Continued)

	Oil (MMBbls)			Natural Gas (Bcf)		
	United States	International	Total	United States	International	Total
Proved Reserves						
December 31, 2015	525	188	713	5,991	30	6,021
Revisions of prior estimates [1]	11	3	14	310	—	310
Extensions, discoveries, and other additions	24	—	24	59	—	59
Purchases in place	81	—	81	68	—	68
Sales in place	(14)	—	(14)	(1,263)	—	(1,263)
Production	(86)	(30)	(116)	(766)	(5)	(771)
December 31, 2016	541	161	702	4,399	25	4,424
Revisions of prior estimates [1]	47	23	70	644	12	656
Extensions, discoveries, and other additions	72	5	77	119	6	125
Purchases in place	1	—	1	6	—	6
Sales in place	(63)	—	(63)	(1,514)	—	(1,514)
Production	(97)	(32)	(129)	(461)	(6)	(467)
December 31, 2017	**501**	**157**	**658**	**3,193**	**37**	**3,230**
Revisions of prior estimates [1]	**65**	**12**	**77**	**220**	**—**	**220**
Extensions, discoveries, and other additions	**104**	**—**	**104**	**190**	**—**	**190**
Sales in place	**(34)**	**—**	**(34)**	**(15)**	**—**	**(15)**
Production	**(107)**	**(31)**	**(138)**	**(390)**	**(5)**	**(395)**
December 31, 2018	**529**	**138**	**667**	**3,198**	**32**	**3,230**
Proved Developed Reserves						
December 31, 2015	332	159	491	5,184	30	5,214
December 31, 2016	360	147	507	3,637	25	3,662
December 31, 2017	361	136	497	2,640	24	2,664
December 31, 2018	**392**	**123**	**515**	**2,564**	**24**	**2,588**
Proved Undeveloped Reserves						
December 31, 2015	193	29	222	807	—	807
December 31, 2016	181	14	195	762	—	762
December 31, 2017	140	21	161	553	13	566
December 31, 2018	**137**	**15**	**152**	**634**	**8**	**642**

[1] Revisions of prior estimates include the effects of new infill drilling, changes in commodity prices, and other updates, including changes in economic conditions, changes in reservoir performance, and changes to development plans. Additions generated by Anadarko's infill-drilling programs were 181 MMBOE for 2018, 71 MMBOE for 2017, and 69 MMBOE for 2016.

Oil and Gas Reserves (Continued)

	NGLs (MMBbls)			Total (MMBOE)		
	United States	International	Total	United States	International	Total
Proved Reserves						
December 31, 2015	325	15	340	1,849	208	2,057
Revisions of prior estimates [1]	45	2	47	108	5	113
Extensions, discoveries, and other additions	6	—	6	40	—	40
Purchases in place	5	—	5	97	—	97
Sales in place	(69)	—	(69)	(294)	—	(294)
Production	(44)	(2)	(46)	(258)	(33)	(291)
December 31, 2016	268	15	283	1,542	180	1,722
Revisions of prior estimates [1]	45	(2)	43	199	23	222
Extensions, discoveries, and other additions	16	—	16	108	6	114
Purchases in place	1	—	1	3	—	3
Sales in place	(64)	—	(64)	(379)	—	(379)
Production	(34)	(2)	(36)	(208)	(35)	(243)
December 31, 2017	**232**	**11**	**243**	**1,265**	**174**	**1,439**
Revisions of prior estimates [1]	**34**	**1**	**35**	**136**	**13**	**149**
Extensions, discoveries, and other additions	**28**	**—**	**28**	**164**	**—**	**164**
Purchases in place	**—**	**—**	**—**	**—**	**—**	**—**
Sales in place	**—**	**—**	**—**	**(37)**	**—**	**(37)**
Production	**(36)**	**(2)**	**(38)**	**(208)**	**(34)**	**(242)**
December 31, 2018	**258**	**10**	**268**	**1,320**	**153**	**1,473**
Proved Developed Reserves						
December 31, 2015	257	15	272	1,453	179	1,632
December 31, 2016	193	15	208	1,159	166	1,325
December 31, 2017	176	10	186	977	150	1,127
December 31, 2018	**192**	**10**	**202**	**1,011**	**137**	**1,148**
Proved Undeveloped Reserves						
December 31, 2015	68	—	68	396	29	425
December 31, 2016	75	—	75	383	14	397
December 31, 2017	56	1	57	288	24	312
December 31, 2018	**66**	**—**	**66**	**309**	**16**	**325**

(1) Revisions of prior estimates include the effects of new infill drilling, changes in commodity prices, and other updates, including changes in economic conditions, changes in reservoir performance, and changes to development plans. Additions generated by Anadarko's infill-drilling programs were 181 MMBOE for 2018, 71 MMBOE for 2017, and 69 MMBOE for 2016.

Total proved reserves increased by 34 MMBOE in 2018 primarily due to the following:

Revisions of prior estimates Prior estimates of proved reserves were revised upward by 149 MMBOE.

MMBOE	December 31, 2018
Revisions due to changes in year-end prices (price impact to opening balance)	29
Other revisions of prior estimates	
Revisions due to performance	4
Revisions due to cost updates	(10)
Revisions due to successful infill drilling	181
Revisions due to development plan updates	(51)
Other revisions	(4)
Total other revisions of prior estimates	120
Revisions of prior estimates	149

Positive revisions of 29 MMBOE were due to the improvement in commodity prices. The positive price-related revisions supplemented a net increase of 120 MMBOE primarily associated with the following:

– ***Performance*** The Company experienced an overall increase of 4 MMBOE in proved reserves due to performance improvements. Numerous areas of the Company contributed to a total upward revision of 48 MMBOE with assets in the Gulf of Mexico primarily responsible for the positive changes. Downward revisions of 44 MMBOE were primarily due to vertical well performance reductions in the DJ basin and performance reductions in the Lucius, K2, and Nansen areas in the Gulf of Mexico.

– ***Cost updates*** Annual updates to cost forecasts resulted in a minor reduction in proved reserves primarily associated with the Greater Natural Buttes area in the Rockies.

– ***Infill-drilling activities*** The Company added 181 MMBOE of proved reserves associated with infill-drilling activities, with 168 MMBOE in the DJ basin, 5 MMBOE in the Gulf of Mexico K2 area, 5 MMBOE in the Gulf of Mexico Lucius area, and the remaining in the Ghana TEN field.

– ***Development plan updates*** The majority of revisions associated with updates to development plans occurred in the DJ basin due to municipal permit delays in certain areas of the field.

Extensions, discoveries, and other additions Proved reserves increased by 164 MMBOE through the extension and discovery of proved acreage in various areas of the Company. Approximately 119 MMBOE was associated with the extension of proved acreage resulting from ongoing development activities in the Delaware basin, 24 MMBOE was associated with the Hadrian North expansion area in the Gulf of Mexico, 7 MMBOE was associated with the Marlin area in the Gulf of Mexico, 6 MMBOE was associated with the Constellation discovery in the Gulf of Mexico and the remaining 8 MMBOE was associated with various other drilling related acreage extensions in the Rockies.

Sales in place Proved reserves decreased by 37 MMBOE due to the divestiture of the Company's assets in Alaska and the Ram Powell field in the Gulf of Mexico. The decrease was comprised of 30 MMBOE of proved developed reserves and 7 MMBOE of PUD reserves.

Total proved reserves decreased by 283 MMBOE in 2017 primarily due to the following:

Revisions of prior estimates Prior estimates of proved reserves were revised upward by 222 MMBOE.

MMBOE	**December 31, 2017**
Revisions due to changes in year-end prices (price impact to opening balance)	92
Other revisions of prior estimates	
Revisions due to performance	60
Revisions due to cost reductions	(4)
Revisions due to successful infill drilling	71
Revisions due to development plan updates	5
Other revisions	(2)
Total other revisions of prior estimates	130
Revisions of prior estimates	222

Positive revisions of 92 MMBOE were due to the improvement in commodity prices. The positive price-related revisions supplemented a net increase of 130 MMBOE primarily associated with the following:

– ***Performance*** The Company experienced an overall increase of 60 MMBOE in proved reserves due to performance improvements. Numerous areas of the Company contributed to a total upward revision of 91 MMBOE, with the largest increases occurring in the DJ and Delaware basins. Downward revisions of 31 MMBOE were primarily due to performance reductions in the Lucius area in the Gulf of Mexico and in the Greater Natural Buttes area of the Rockies.

– ***Cost updates*** Annual updates reflected cost increases in certain U.S. onshore areas resulting in a minor reduction in proved reserves.

– ***Infill-drilling activities*** The Company added 71 MMBOE of proved reserves associated with infill-drilling activities, with 53 MMBOE in the DJ basin, 13 MMBOE in the Lucius and Holstein areas in the Gulf of Mexico, and the remaining in the Ghana Jubilee field.

– ***Development plan updates*** The majority of revisions associated with updates to development plans occurred in the DJ basin due to ongoing optimization of development activity.

Extensions, discoveries, and other additions Proved reserves increased by 114 MMBOE primarily through the extension of proved acreage. Approximately 89 MMBOE was associated with drilling activities in the Delaware basin, 10 MMBOE in the Horn Mountain area in the Gulf of Mexico, and 6 MMBOE in the Ghana Jubilee field. The remaining 9 MMBOE was associated with various other U.S. areas.

Sales in place Proved reserves decreased by 379 MMBOE due to the divestiture of certain U.S. onshore properties. The decrease was comprised of 300 MMBOE of proved developed reserves and 79 MMBOE of PUDs.

Total proved reserves decreased by 335 MMBOE in 2016 primarily due to the following:

Revisions of prior estimates Prior estimates of proved reserves were revised downward by 113 MMBOE.

MMBOE	**December 31, 2016**
Revisions due to changes in year-end prices (price impact to opening balance)	(147)
Other revisions of prior estimates	
Revisions due to performance	74
Revisions due to cost reductions	100
Revisions due to successful infill drilling	69
Revisions due to development plan updates	(3)
Other revisions	20
Total other revisions of prior estimates	260
Revisions of prior estimates	113

Negative revisions of 147 MMBOE were due to the decline in commodity prices. The negative price-related revisions were offset by a net increase of 260 MMBOE associated with the following:

– ***Performance*** The Company experienced an overall increase of 74 MMBOE in proved reserves. Upward revisions of 102 MMBOE were primarily due to improved well performance in the DJ basin, certain U.S. shale plays, and select wells in the Gulf of Mexico. Downward revisions of 28 MMBOE were primarily due to performance updates associated with select wells in the Gulf of Mexico.

– ***Cost reductions*** Ongoing cost-optimization efforts and a reduced cost structure associated with the lower commodity-price environment resulted in an increase in proved reserves. The Eagleford and the DJ basin areas experienced an increase of 94 MMBOE of proved reserves associated with certain wells, included in the negative price-related revisions, which experienced restored economic producibility upon reduction of the cost structure. The remaining increase in proved reserves due to the improved cost structure is attributable to numerous areas across the Company.

– ***Infill-drilling activities*** The Company added 69 MMBOE of proved reserves associated with infill-drilling activities, with the majority in the DJ basin and the K2 and Caesar/Tonga areas of the Gulf of Mexico.

– ***Other revisions*** Other revisions resulted from the Company's multi-step reserves reconciliation process and the elimination of duplicative adjustments to the opening reserves balance.

Extensions, discoveries, and other additions Proved reserves increased by 40 MMBOE through the extension of proved acreage, primarily as a result of successful drilling in the Delaware basin. Although shale plays represented only 20% of the Company's total proved reserves at December 31, 2016, growth in the shale plays contributed a majority of the total extensions and discoveries.

Purchases in place Proved reserves increased by 97 MMBOE due to the GOM Acquisition. The increase was comprised of 67 MMBOE of proved developed reserves and 30 MMBOE of PUDs.

Sales in place Proved reserves decreased by 294 MMBOE due to the divestiture of certain U.S. onshore properties. The decrease was comprised of 279 MMBOE of proved developed reserves and 15 MMBOE of PUDs.

Capitalized Costs

Capitalized costs include the cost of properties, equipment, and facilities for oil and natural-gas producing activities. Capitalized costs for proved properties include costs for oil and natural-gas leaseholds where proved reserves have been identified, development wells, and related equipment and facilities, including development wells in progress. Capitalized costs for unproved properties include costs for acquiring oil and gas leaseholds where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or in active completion, and costs of exploratory wells suspended or waiting on completion. Capitalized costs associated with activities of the Company's WES Midstream and Other Midstream reporting segments, LNG facilities costs, and other corporate activities are not included.

millions	United States	International	Total
December 31, 2018			
Capitalized			
Unproved properties	**$ 1,453**	**$ 214**	**$ 1,667**
Proved properties	**43,945**	**5,978**	**49,923**
	45,398	**6,192**	**51,590**
Less accumulated DD&A	**29,898**	**3,859**	**33,757**
Net capitalized costs	**$ 15,500**	**$ 2,333**	**$ 17,833**
December 31, 2017			
Capitalized			
Unproved properties	$ 2,099	$ 284	$ 2,383
Proved properties	40,969	5,773	46,742
	43,068	6,057	49,125
Less accumulated DD&A	27,511	3,279	30,790
Net capitalized costs	$ 15,557	$ 2,778	$ 18,335

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

Amounts reported as costs incurred include both capitalized costs and costs charged to expense when incurred for oil and gas property acquisition, exploration, and development activities. Costs incurred also include new AROs established in the current year as well as increases or decreases to the AROs resulting from changes to cost estimates during the year. Exploration costs presented below include the costs of drilling and equipping successful and unsuccessful exploration wells during the year, geological and geophysical expenses, and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells, and construction of related production facilities. Costs associated with activities of the Company's WES Midstream and Other Midstream reporting segments, LNG facilities costs, and other corporate activities are not included.

millions	United States	International	Total
Year Ended December 31, 2018			
Property acquisitions			
Unproved	**$ 202**	**$ —**	**$ 202**
Proved	**43**	**—**	**43**
Exploration	**491**	**78**	**569**
Development	**3,624**	**129**	**3,753**
Total costs incurred	**$ 4,360**	**$ 207**	**$ 4,567**
Year Ended December 31, 2017			
Property acquisitions			
Unproved	$ 490	$ 9	$ 499
Proved	7	—	7
Exploration	661	318	979
Development	2,579	29	2,608
Total costs incurred	$ 3,737	$ 356	$ 4,093
Year Ended December 31, 2016			
Property acquisitions			
Unproved	$ 178	$ 9	$ 187
Proved	2,498	—	2,498
Exploration	398	433	831
Development	1,780	337	2,117
Total costs incurred	$ 4,854	$ 779	$ 5,633

RESULTS OF OPERATIONS

Results of operations consists of all oil and gas producing activities within the Exploration and Production reporting segment.

millions	United States	International	Total
Year Ended December 31, 2018			
Net revenues from production			
Third-party sales	$ 7,428	$ 910	$ 8,338
Sales to consolidated affiliates	1,643	1,501	3,144
Gains (losses) on property dispositions	20	—	20
Total revenues	9,091	2,411	11,502
Oil and gas operating	906	247	1,153
Production, property, and other taxes	355	405	760
Oil and gas transportation	844	34	878
Technical support and other [(1)]	310	28	338
Exploration expenses	417	42	459
DD&A	3,198	601	3,799
Impairments related to oil and gas properties	373	—	373
Other operating expense	141	8	149
Total expenses	6,544	1,365	7,909
Results of operations before income taxes	2,547	1,046	3,593
Income tax expense (benefit) [(2)]	585	590	1,175
Results of operations	$ 1,962	$ 456	$ 2,418

(1) Represents administrative costs that are related to oil and gas operations.

(2) Income tax expense is calculated by applying the current statutory tax rates to revenues after deducting costs, which include DD&A allowances, after giving effect to permanent differences.

RESULTS OF OPERATIONS (Continued)

millions	United States	International	Total
Year Ended December 31, 2017			
Net revenues from production			
Third-party sales	$ 5,429	$ 710	$ 6,139
Sales to consolidated affiliates	1,746	1,084	2,830
Gains (losses) on property dispositions	520	13	533
Total revenues	7,695	1,807	9,502
Oil and gas operating	791	198	989
Production, property, and other taxes	226	290	516
Oil and gas transportation	881	33	914
Technical support and other [(1)]	342	17	359
Exploration expenses	1,692	843	2,535
DD&A	3,260	634	3,894
Impairments related to oil and gas properties	229	—	229
Other operating expense	106	108	214
Total expenses	7,527	2,123	9,650
Results of operations before income taxes	168	(316)	(148)
Income tax expense (benefit) [(2)]	62	191	253
Results of operations	$ 106	$ (507)	$ (401)
Year Ended December 31, 2016			
Net revenues from production			
Third-party sales	$ 3,884	$ 619	$ 4,503
Sales to consolidated affiliates	1,871	779	2,650
Gains (losses) on property dispositions	(855)	(6)	(861)
Total revenues	4,900	1,392	6,292
Oil and gas operating	603	204	807
Production, property, and other taxes	189	282	471
Oil and gas transportation	964	38	1,002
Technical support and other [(1)]	317	22	339
Exploration expenses	538	406	944
DD&A	3,512	395	3,907
Impairments related to oil and gas properties	55	—	55
Other operating expense	62	49	111
Total expenses	6,240	1,396	7,636
Results of operations before income taxes	(1,340)	(4)	(1,344)
Income tax expense (benefit) [(2)]	(491)	155	(336)
Results of operations	$ (849)	$ (159)	$ (1,008)

(1) Represents administrative costs that are related to oil and gas operations.

(2) Income tax expense is calculated by applying the current statutory tax rates to revenues after deducting costs, which include DD&A allowances, after giving effect to permanent differences.

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

Estimates of future net cash flows from proved reserves are computed based on the average beginning-of-the-month prices during the 12-month period for the year. Estimated future net cash flows for all periods presented are reduced by estimated future development, production, and abandonment and dismantlement costs based on existing costs, assuming continuation of existing economic conditions, and by estimated future income tax expense. These estimates also include assumptions about the timing of future production of proved reserves, and timing of future development, production costs, and abandonment and dismantlement. Income tax expense, both U.S. and foreign, is calculated by applying the existing statutory tax rates, including the reduced rate effective for years after 2017 due to the Tax Reform Legislation, to the pretax net cash flows, giving effect to any permanent differences and reduced by the applicable tax basis. The effect of tax credits is considered in determining the income tax expense. The 10% discount factor is prescribed by GAAP.

The present value of future net cash flows is not an estimate of the fair value of Anadarko's oil and gas properties. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves, and a discount factor more representative of the time value of money and the risks inherent in producing oil and natural gas. Significant changes in estimated reserves volume or commodity prices could have a material effect on the Company's Consolidated Financial Statements.

millions	United States	International	Total
December 31, 2018			
Future cash inflows	**$ 49,540**	**$ 10,058**	**$ 59,598**
Future production costs	**19,715**	**3,073**	**22,788**
Future development costs	**5,216**	**444**	**5,660**
Future income tax expenses	**4,868**	**2,728**	**7,596**
Future net cash flows	**19,741**	**3,813**	**23,554**
10% annual discount for estimated timing of cash flows	**5,606**	**806**	**6,412**
Standardized measure of discounted future net cash flows	**$ 14,135**	**$ 3,007**	**$ 17,142**
December 31, 2017			
Future cash inflows	$ 38,909	$ 8,741	$ 47,650
Future production costs	16,947	3,164	20,111
Future development costs	5,512	679	6,191
Future income tax expenses	3,106	2,147	5,253
Future net cash flows	13,344	2,751	16,095
10% annual discount for estimated timing of cash flows	3,856	579	4,435
Standardized measure of discounted future net cash flows	$ 9,488	$ 2,172	$ 11,660
December 31, 2016			
Future cash inflows	$ 33,513	$ 7,328	$ 40,841
Future production costs	16,921	3,290	20,211
Future development costs	7,292	566	7,858
Future income tax expenses	2,606	1,408	4,014
Future net cash flows	6,694	2,064	8,758
10% annual discount for estimated timing of cash flows	1,658	470	2,128
Standardized measure of discounted future net cash flows	$ 5,036	$ 1,594	$ 6,630

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

millions	United States	International	Total
2018			
Balance at January 1	**$ 9,488**	**$ 2,172**	**$ 11,660**
Sales and transfers of oil and gas produced, net of production costs	**(6,657)**	**(1,703)**	**(8,360)**
Net changes in prices and production costs	**3,847**	**2,351**	**6,198**
Changes in estimated future development costs	**(1,957)**	**124**	**(1,833)**
Extensions, discoveries, additions, and improved recovery, less related costs	**3,429**	**—**	**3,429**
Development costs incurred during the period	**2,677**	**86**	**2,763**
Revisions of previous quantity estimates	**4,023**	**329**	**4,352**
Purchases of minerals in place	**5**	**—**	**5**
Sales of minerals in place	**(417)**	**—**	**(417)**
Accretion of discount	**1,161**	**382**	**1,543**
Net change in income taxes	**(1,268)**	**(461)**	**(1,729)**
Other	**(196)**	**(273)**	**(469)**
Balance at December 31	**$ 14,135**	**$ 3,007**	**$ 17,142**
2017			
Balance at January 1	$ 5,036	$ 1,594	$ 6,630
Sales and transfers of oil and gas produced, net of production costs	(4,924)	(1,260)	(6,184)
Net changes in prices and production costs	5,116	1,591	6,707
Changes in estimated future development costs	184	(92)	92
Extensions, discoveries, additions, and improved recovery, less related costs	1,478	98	1,576
Development costs incurred during the period	1,304	6	1,310
Revisions of previous quantity estimates	2,918	882	3,800
Purchases of minerals in place	28	—	28
Sales of minerals in place	(864)	—	(864)
Accretion of discount	674	260	934
Net change in income taxes	(416)	(641)	(1,057)
Other	(1,046)	(266)	(1,312)
Balance at December 31	$ 9,488	$ 2,172	$ 11,660

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Continued)

millions	United States	International	Total
2016			
Balance at January 1	$ 7,092	$ 2,593	$ 9,685
Sales and transfers of oil and gas produced, net of production costs	(3,678)	(856)	(4,534)
Net changes in prices and production costs	(1,953)	(1,607)	(3,560)
Changes in estimated future development costs	742	(126)	616
Extensions, discoveries, additions, and improved recovery, less related costs	429	—	429
Development costs incurred during the period	1,223	203	1,426
Revisions of previous quantity estimates	1,388	320	1,708
Purchases of minerals in place	193	—	193
Sales of minerals in place	(1,277)	—	(1,277)
Accretion of discount	949	431	1,380
Net change in income taxes	690	717	1,407
Other	(762)	(81)	(843)
Balance at December 31	$ 5,036	$ 1,594	$ 6,630

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

None.

Item 9A. Controls and Procedures

EVALUATION AND DISCLOSURE CONTROLS AND PROCEDURES

Anadarko's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (Exchange Act). The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2018.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See *Report of Independent Registered Public Accounting Firm* under Item 8 of this Form 10-K.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in Anadarko's internal control over financial reporting during the fourth quarter of 2018 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

See *Anadarko Board of Directors, Corporate Governance—Committees of the Board, Corporate Governance—Board of Directors,* and *Section 16(a) Beneficial Ownership Reporting Compliance* in the Definitive Proxy Statement (Proxy Statement) for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 14, 2019 (to be filed with the SEC prior to April 4, 2019), each of which is incorporated herein by reference.

See list of *Executive Officers of the Registrant* under Items 1 and 2 of this Form 10-K, which is incorporated herein by reference.

The Company's Code of Business Conduct and Ethics and the Code of Ethics for the Chief Executive Officer, Chief Financial Officer, and Chief Accounting Officer (Code of Ethics) can be found on the Company's website located at www.anadarko.com/Responsibility/Good-Governance. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

Item 11. Executive Compensation

See *Corporate Governance—Board of Directors—Compensation and Benefits Committee Interlocks and Insider Participation, Corporate Governance—Board of Directors—Director Compensation, Corporate Governance—Director Compensation Table for 2018, Compensation and Benefits Committee Report on 2018 Executive Compensation, Compensation Discussion and Analysis,* and *Executive Compensation* in the Proxy Statement, each of which is incorporated herein by reference. The Compensation and Benefits Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

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

See *Security Ownership of Certain Beneficial Owners and Management* in the Proxy Statement and *Securities Authorized for Issuance under Equity Compensation Plans* under Item 5 of this Form 10-K, each of which is incorporated herein by reference.

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

See *Corporate Governance—Board of Directors* and *Transactions with Related Persons* in the Proxy Statement, each of which is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

See *Independent Auditor* in the Proxy Statement, which is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

a) EXHIBITS

The following documents are filed as part of this Form 10-K or incorporated by reference:

(1) The consolidated financial statements of Anadarko Petroleum Corporation are listed on the Index to this Form 10-K, page 87.

(2) Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith or double asterisk (**) and are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing under File Number 1-8968 as indicated.

	Exhibit Number	Description
	2 (i)	Agreement and Plan of Merger dated as of June 22, 2006, among Anadarko Petroleum Corporation, APC Acquisition Sub, Inc. and Kerr-McGee Corporation, filed as Exhibit 2.2 to Form 8-K filed on June 26, 2006
#	(ii)	Contribution Agreement and Agreement and Plan of Merger, dated as of November 7, 2018, by and among Anadarko Petroleum Corporation, Anadarko E&P Onshore LLC, APC Midstream Holdings, LLC, Western Gas Equity Partners, LP, Western Gas Equity Holdings, LLC, Western Gas Partners, LP, Western Gas Holdings, LLC, Clarity Merger Sub, LLC, WGR Asset Holding Company LLC, WGR Operating, LP, Kerr-McGee Gathering LLC, Kerr-McGee Worldwide Corporation and Delaware Basin Midstream, LLC, filed as Exhibit 2.1 to Form 8-K filed on November 9, 2018
	3 (i)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated May 21, 2009, filed as Exhibit 3.3 to Form 8-K filed on May 22, 2009
	(ii)	By-Laws of Anadarko Petroleum Corporation, amended and restated as of November 14, 2018, filed as Exhibit 3.1 to Form 8-K filed on November 20, 2018
	4 (i)	Trustee Indenture, dated as of September 19, 2006, Anadarko Petroleum Corporation to The Bank of New York Trust Company, N.A., filed as Exhibit 4.1 to Form 8-K filed on September 19, 2006
	(ii)	Third Supplemental Indenture, dated as of June 10, 2015, between Anadarko Petroleum Corporation and The Bank of New York Mellon Trust Company, N.A., filed as Exhibit 4.2 to Form 8-K filed on June 10, 2015
	(iii)	Second Supplemental Indenture dated October 4, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A., filed as Exhibit 4.1 to Form 8-K filed on October 6, 2006
	(iv)	Ninth Supplemental Indenture dated October 4, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A., filed as Exhibit 4.2 to Form 8-K filed on October 6, 2006
	(v)	Officers' Certificate of Anadarko Petroleum Corporation, dated March 2, 2009, establishing the 7.625% Senior Notes due 2014 and the 8.700% Senior Notes due 2019, filed as Exhibit 4.1 to Form 8-K filed on March 6, 2009
	(vi)	Form of 8.700% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on March 6, 2009
	(vii)	Officers' Certificate of Anadarko Petroleum Corporation, dated June 9, 2009, establishing the 5.75% Senior Notes due 2014, the 6.95% Senior Notes due 2019 and the 7.95% Senior Notes due 2039, filed as Exhibit 4.1 to Form 8-K filed on June 12, 2009
	(viii)	Form of 6.95% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on June 12, 2009
	(ix)	Form of 7.95% Senior Notes due 2039, filed as Exhibit 4.4 to Form 8-K filed on June 12, 2009
	(x)	Officers' Certificate of Anadarko Petroleum Corporation dated March 9, 2010, establishing the 6.200% Senior Notes due 2040, filed as Exhibit 4.1 to Form 8-K filed on March 16, 2010
	(xi)	Form of 6.200% Senior Notes due 2040, filed as Exhibit 4.2 to Form 8-K filed on March 16, 2010

	Exhibit Number		Description
	4	(xii)	Officers' Certificate of Anadarko Petroleum Corporation dated July 7, 2014, establishing the 3.45% Senior Notes due 2024 and the 4.50% Senior Notes due 2044, filed as Exhibit 4.1 to Form 8-K filed on July 7, 2014
		(xiii)	Form of 3.45% Senior Notes due 2024, filed as Exhibit 4.2 to Form 8-K filed on July 7, 2014 (included in Exhibit 4.xiii)
		(xiv)	Form of 4.50% Senior Notes due 2044, filed as Exhibit 4.3 to Form 8-K filed on July 7, 2014 (included in Exhibit 4.xiii)
		(xv)	Officers' Certificate of Anadarko Petroleum Corporation dated March 17, 2016, establishing the 4.85% Senior Notes due 2021 and the 5.55% Senior Notes due 2026, and the 6.60% Senior Notes due 2046, filed as Exhibit 4.1 to Form 8-K filed on March 17, 2016
		(xvi)	Form of 4.85% Senior Notes due 2021, filed as Exhibit 4.2 to Form 8-K filed on March 17, 2016 (included in Exhibit 4.xx)
		(xvii)	Form of 5.55% Senior Notes due 2026, filed as Exhibit 4.3 to Form 8-K filed on March 17, 2016 (included in Exhibit 4.xx)
		(xviii)	Form of 6.60% Senior Notes due 2046, filed as Exhibit 4.4 to Form 8-K filed on March 17, 2016 (included in Exhibit 4.xx)
†	10	(i)	1998 Director Stock Plan of Anadarko Petroleum Corporation, effective January 30, 1998, filed as Appendix A to DEF 14A filed on March 16, 1998
†		(ii)	Form of Anadarko Petroleum Corporation 1998 Director Stock Plan Stock Option Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 17, 2005
†		(iii)	Key Employee Change of Control Contract, filed as Exhibit 10(b)(xxii) to Form 10-K for year ended December 31, 1997, filed on March 18, 1998
†		(iv)	First Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract, filed as Exhibit 10(b) to Form 10-Q for quarter ended September 30, 2000, filed on November 13, 2000
†		(v)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract, filed as Exhibit 10(b)(ii) to Form 10-Q for quarter ended June 30, 2003, filed on August 11, 2003
†		(vi)	Form of Key Employee Change of Control Contract (2011), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2011, filed on July 27, 2011
†		(vii)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract (Applicable to Vice Presidents Other Than Executive Officers as of October 2013), filed as Exhibit 10(ii) to Form 10-Q for quarter ended March 31, 2015, filed on May 4, 2015
†		(viii)	Form of Anadarko Petroleum Corporation Key Employee Change of Control Contract for Executive Vice Presidents, filed as Exhibit 10(xvii) to Form 10-K for year ended December 31, 2016, filed on February 17, 2017
†		(ix)	Letter Agreement regarding Post-Retirement Benefits, dated February 16, 2004—Robert J. Allison, Jr., filed as Exhibit 10(b)(xxxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†		(x)	Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2017), filed as Exhibit 10(b)(x) to Form 10-K for year ended December 31, 2017, filed on February 15, 2018
†		(xi)	Anadarko Retirement Restoration Plan (As Amended and Restated Effective as of January 1, 2017), filed as Exhibit 10(b)(xi) to Form 10-K for year ended December 31, 2017, filed on February 15, 2018
†		(xii)	Kerr-McGee Corporation Benefits Retirement Restoration Plan (As Amended and Restated Effective January 1, 2017), filed as Exhibit 10(b)(xii) to Form 10-K for year ended December 31, 2017, filed on February 15, 2018
†		(xiii)	Anadarko Petroleum Corporation Estate Enhancement Program, filed as Exhibit 10(b)(xxxiv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999
†		(xiv)	Estate Enhancement Program Agreement between Anadarko Petroleum Corporation and Eligible Executives, filed as Exhibit 10(b)(xxxv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999
†		(xv)	Estate Enhancement Program Agreements effective November 29, 2000, filed as Exhibit 10(b)(xxxxii) to Form 10-K for year ended December 31, 2000, filed on March 15, 2001

	Exhibit Number	Description
†	10 (xvi)	Anadarko Petroleum Corporation Management Life Insurance Plan, restated November 1, 2002, filed as Exhibit 10(b)(xxxii) to Form 10-K for year ended December 31, 2002, filed on March 14, 2003
†	(xvii)	First Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective June 30, 2003, filed as Exhibit 10(b)(xliii) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†	(xviii)	Second Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective January 1, 2008, filed as Exhibit 10(xxix) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010
†	(xix)	Anadarko Petroleum Corporation Officer Severance Plan, filed as Exhibit 10(b)(iv) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003
†	(xx)	Form of Termination Agreement and Release of All Claims Under Officer Severance Plan, filed as Exhibit 10.1 to Form 8-K filed on August 24, 2016
†	(xxi)	Form of Director and Officer Indemnification Agreement, filed as Exhibit 10 to Form 8-K filed on September 3, 2004
†	(xxii)	Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan, effective as of May 20, 2008, filed as Exhibit 10.1 to Form 8-K filed on May 27, 2008
†	(xxiii)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Stock Option Award Agreement, filed as Exhibit 10.3 to Form 8-K filed on November 13, 2009
†	(xxiv)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 13, 2009
†	(xxv)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 13, 2009
†	(xxvi)	Anadarko Petroleum Corporation 2008 Director Compensation Plan, effective as of May 20, 2008, filed as Exhibit 10.2 to Form 8-K filed on May 27, 2008
†	(xxvii)	First Amendment to Anadarko Petroleum Corporation 2008 Director Compensation Plan, dated February 8, 2016, filed as Exhibit 10(xli) to Form 10-K for year ended December 31, 2015, filed on February 17, 2016
†	(xxviii)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10.3 to Form 8-K filed on May 27, 2008
†	(xxix)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan (2013), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2013, filed on July 29, 2013
†	(xxx)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan Annual Deferred Shares (2016), filed as Exhibit 10(iii) to Form 10-Q for quarter ended March 31, 2016, filed on May 2, 2016
†	(xxxi)	Terms and Conditions of Elective Deferred Share Awards for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10(iv) to Form 10-Q for quarter ended March 31, 2016, filed on May 2, 2016
†	(xxxii)	Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2012), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2014, filed on July 29, 2014
†	(xxxiii)	First Amendment, dated December 17, 2013, to the Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2012), filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2014, filed on July 29, 2014
†	(xxxiv)	Severance Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated February 16, 2012, filed as Exhibit 10.2 to Form 8-K filed on February 21, 2012
†	(xxxv)	Time Sharing Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated May 15, 2012, filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2012, filed on August 8, 2012
†	(xxxvi)	First Amendment to Time Sharing Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated June 2, 2015, filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2015, filed on July 28, 2015
†	(xxxvii)	Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, effective as of May 15, 2012, filed as Exhibit 10.1 to Form 8-K filed on May 15, 2012

	Exhibit Number	Description
†	10 (xxxviii)	Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, filed as Exhibit 10.1 to Form 8-K filed on May 16, 2016
†	(xxxix)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Stock Option Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on May 15, 2012
†	(xl)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.3 to Form 8-K filed on May 15, 2012
†	(xli)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.4 to Form 8-K filed on May 15, 2012
†	(xlii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 9, 2012
†	(xliii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 9, 2012
†	(xliv)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement (2014), filed as Exhibit 10.1 to Form 8-K filed on November 10, 2014
†	(xlv)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Stock Option Award Agreement, filed as Exhibit 10(i) to Form 10-Q for quarter ended September 30, 2016, filed on October 31, 2016
†	(xlvi)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Restricted Stock Unit Award Agreement, filed as Exhibit 10(ii) to Form 10-Q for quarter ended September 30, 2016, filed on October 31, 2016
†	(xlvii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Performance Unit Award Agreement, filed as Exhibit 10(iii) to Form 10-Q for quarter ended September 30, 2016, filed on October 31, 2016
†	(xlviii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Stock Option Award Agreement (November 2018), filed as Exhibit 10.1 to Form 8-K filed on November 20, 2018
†	(xlix)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Restricted Stock Unit Award Agreement (November 2018), filed as Exhibit 10.2 to Form 8-K filed on November 20, 2018
†	(l)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Performance Unit Award Agreement (November 2018), filed as Exhibit 10.3 to Form 8-K filed on November 20, 2018
†	(li)	Terms and Conditions of Elective Deferred Share Awards for the Anadarko Petroleum Corporation 2008 Director Compensation Plan and the Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, each as amended, filed as Exhibit 10(iii) to Form 10-Q filed for quarter ended March 30, 2018, filed on May 1, 2018
†	(lii)	Form of Director Annual Deferred Shares Award Letter for Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, filed as Exhibit 10(i) to Form 10-Q filed for quarter ended June 30, 2018, filed on July 31, 2018
	(liii)	Settlement Agreement dated as of April 3, 2014, by and among (1) the Anadarko Litigation Trust, (2) the United States of America in its capacity as plaintiff-intervenor in the Tronox Adversary Proceeding and acting for and on behalf of certain U.S. government agencies and (3) Anadarko Petroleum Corporation, Kerr-McGee Corporation, and certain other subsidiaries, filed as Exhibit 10.1 to Form 8-K filed on April 3, 2014
	(liv)	Credit Agreement, dated as of June 17, 2014, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., Citibank, N.A., The Royal Bank of Scotland plc, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on June 23, 2014
	(lv)	First Amendment to Credit Agreement, dated November 14, 2014, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on November 19, 2014

	Exhibit Number		Description
	10	(lvi)	Amendment and Maturity Extension Agreement, dated December 14, 2015, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on December 18, 2015
		(lvii)	Third Amendment and Maturity Extension Agreement, dated January 12, 2018, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on January 16, 2018
		(lviii)	Fourth Amendment to Credit Agreement, dated December 20, 2018, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on December 27, 2018
		(lix)	Form of Commercial Paper Dealer Agreement for Commercial Paper Program, filed as Exhibit 10.1 to Form 8-K filed on January 21, 2015
†		(lx)	Anadarko Petroleum Corporation Key Employee Change of Control Contract, dated June 1, 2015, for Christopher O. Champion, filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2015, filed on July 28, 2015
		(lxi)	364-Day Revolving Credit Agreement, dated as of January 19, 2016, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd., Citibank, N.A., and Mizuho Bank, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on January 25, 2016
		(lxii)	First Amendment to 364-Day Revolving Credit Agreement, dated January 13, 2017, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on January 20, 2017
		(lxiii)	Second Amendment to 364-Day Revolving Credit Agreement, dated January 12, 2018, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the additional lenders party thereto, filed as Exhibit 10.2 to Form 8-K filed on January 16, 2018
*	21		List of Subsidiaries
*	23	(i)	Consent of KPMG LLP
*	23	(ii)	Consent of Miller and Lents, Ltd.
*	24		Power of Attorney
*	31	(i)	Rule 13a-14(a)/15d-14(a) Certification—Chief Executive Officer
*	31	(ii)	Rule 13a-14(a)/15d-14(a) Certification—Chief Financial Officer
**	32		Section 1350 Certifications
*	99		Report of Miller and Lents, Ltd.
*	101	.INS	XBRL Instance Document
*	101	.SCH	XBRL Schema Document
*	101	.CAL	XBRL Calculation Linkbase Document
*	101	.DEF	XBRL Definition Linkbase Document
*	101	.LAB	XBRL Label Linkbase Document
*	101	.PRE	XBRL Presentation Linkbase Document

† Management contracts or compensatory plans or arrangements required to be filed pursuant to Item 15.

Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

The total amount of securities of the registrant authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrants and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the SEC, to furnish copies of any or all of such instruments to the SEC.

b) FINANCIAL STATEMENT SCHEDULES

Financial statement schedules have been omitted because they are not required, not applicable, or the information is included in the Company’s consolidated financial statements.

Item 16. Form 10-K Summary

Not applicable.

SIGNATURES

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

ANADARKO PETROLEUM CORPORATION

February 14, 2019

By: /s/ BENJAMIN M. FINK

Benjamin M. Fink
Executive Vice President, Finance and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 14, 2019.

Name and Signature	Title
(i) Principal executive officer and director:	
/s/ R. A. WALKER R. A. Walker	Chairman and Chief Executive Officer
(ii) Principal financial officer:	
/s/ BENJAMIN M. FINK Benjamin M. Fink	Executive Vice President, Finance and Chief Financial Officer
(iii) Principal accounting officer:	
/s/ CHRISTOPHER O. CHAMPION Christopher O. Champion	Senior Vice President, Chief Accounting Officer and Controller

(iv) Directors:*

ANTHONY R. CHASE
DAVID E. CONSTABLE
H. PAULETT EBERHART
CLAIRE S. FARLEY
PETER J. FLUOR
JOSEPH W. GORDER
JOHN R. GORDON
SEAN GOURLEY
MICHAEL K. GRIMM
MARK C. MCKINLEY
ERIC D. MULLINS
ALEXANDRA PRUNER

* Signed on behalf of each of these persons and on his own behalf:

By: /s/ BENJAMIN M. FINK

Benjamin M. Fink, Attorney-in-Fact

EXHIBIT 31(i)

CERTIFICATIONS

I, R. A. Walker, certify that:

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

February 14, 2019

/s/ R. A. WALKER

R. A. Walker
Chairman and Chief Executive Officer

EXHIBIT 31(ii)

CERTIFICATIONS

I, Benjamin M. Fink, certify that:

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

February 14, 2019

/s/ BENJAMIN M. FINK

Benjamin M. Fink

Executive Vice President, Finance and Chief Financial Officer

EXHIBIT 32

SECTION 1350 CERTIFICATION OF PERIODIC REPORT

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, R. A. Walker, Chairman and Chief Executive Officer of Anadarko Petroleum Corporation (Company), and Benjamin M. Fink, Executive Vice President, Finance and Chief Financial Officer of the Company, certify to the best of our knowledge that:

(1) the Annual Report on Form 10-K of the Company for the period ended December 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (Report), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

February 14, 2019

/s/ R. A. WALKER

R. A. Walker
Chairman and Chief Executive Officer

February 14, 2019

/s/ BENJAMIN M. FINK

Benjamin M. Fink
Executive Vice President, Finance and Chief Financial Officer

This certification is made solely pursuant to 18 U.S.C. Section 1350, and not for any other purpose. A signed original of this written statement required by Section 906 will be retained by Anadarko and furnished to the Securities and Exchange Commission or its staff upon request.