2019

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, 2019**

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 number: **001-32395**

ConocoPhillips

(Exact name of registrant as specified in its charter)

Delaware	**01-0562944**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

925 N. Eldridge Parkway
Houston, TX 77079
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **281-293-1000**

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

Title of each class	Trading symbols	Name of each exchange on which registered
Common Stock, $.01 Par Value	COP	New York Stock Exchange
7% Debentures due 2029	CUSIP—718507BK1	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. [x] 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 [x] 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. [x] 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). [x] Yes [ ] No

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 [x] 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 [x] No

The aggregate market value of common stock held by non-affiliates of the registrant on June 28, 2019, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $61.00, was $67.7 billion.

The registrant had 1,081,132,415 shares of common stock outstanding at January 31, 2020.

Documents incorporated by reference:
Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 12, 2020 (Part III)

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Commonly Used Abbreviations

The following industry-specific, accounting and other terms, and abbreviations may be commonly used in this report.

Currencies

$ or USD	U.S. dollar
CAD	Canadian dollar
GBP	British pound

Units of Measurement

BBL	barrel
BCF	billion cubic feet
BOE	barrels of oil equivalent
MBD	thousands of barrels per day
MCF	thousand cubic feet
MMBOE	million barrels of oil equivalent
MBOED	thousands of barrels of oil equivalent per day
MMBTU	million British thermal units
MMCFD	million cubic feet per day

Industry

CBM	coalbed methane
E&P	exploration and production
FEED	front-end engineering and design
FPS	floating production system
FPSO	floating production, storage and offloading
JOA	joint operating agreement
LNG	liquefied natural gas
NGLs	natural gas liquids
OPEC	Organization of Petroleum Exporting Countries
PSC	production sharing contract
PUDs	proved undeveloped reserves
SAGD	steam-assisted gravity drainage
WCS	Western Canada Select
WTI	West Texas Intermediate

Accounting

ARO	asset retirement obligation
ASC	accounting standards codification
ASU	accounting standards update
DD&A	depreciation, depletion and amortization
FASB	Financial Accounting Standards Board
FIFO	first-in, first-out
G&A	general and administrative
GAAP	generally accepted accounting principles
LIFO	last-in, first-out
NPNS	normal purchase normal sale
PP&E	properties, plants and equipment
SAB	staff accounting bulletin
VIE	variable interest entity

Miscellaneous

EPA	Environmental Protection Agency
EU	European Union
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
HSE	health, safety and environment
ICC	International Chamber of Commerce
ICSID	World Bank's International Centre for Settlement of Investment Disputes
IRS	Internal Revenue Service
OTC	over-the-counter
NYSE	New York Stock Exchange
SEC	U.S. Securities and Exchange Commission
TSR	total shareholder return
U.K.	United Kingdom
U.S.	United States of America

PART I

Unless otherwise indicated, "the company," "we," "our," "us" and "ConocoPhillips" are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2—Business and Properties, contain forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "anticipate," "estimate," "believe," "budget," "continue," "could," "intend," "may," "plan," "potential," "predict," "seek," "should," "will," "would," "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the headings "Risk Factors" beginning on page 21 and "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 70.

Items 1 and 2. BUSINESS AND PROPERTIES

CORPORATE STRUCTURE

ConocoPhillips is an independent E&P company with operations and activities in 17 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; conventional assets in North America, Europe, Asia and Australia; LNG developments; oil sands assets in Canada; and an inventory of global conventional and unconventional exploration prospects. Headquartered in Houston, Texas, at December 31, 2019, we employed approximately 10,400 people worldwide and had total assets of $71 billion.

ConocoPhillips was incorporated in the state of Delaware on November 16, 2001, in connection with, and in anticipation of, the merger between Conoco Inc. and Phillips Petroleum Company. The merger between Conoco and Phillips was consummated on August 30, 2002.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 25—Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a worldwide basis. At December 31, 2019, our operations were producing in the U.S., Norway, Canada, Australia, Timor-Leste, Indonesia, Malaysia, Libya, China and Qatar.

The information listed below appears in the "Oil and Gas Operations" disclosures following the Notes to Consolidated Financial Statements and is incorporated herein by reference:

- Proved worldwide crude oil, NGLs, natural gas and bitumen reserves.
- Net production of crude oil, NGLs, natural gas and bitumen.
- Average sales prices of crude oil, NGLs, natural gas and bitumen.
- Average production costs per BOE.
- Net wells completed, wells in progress and productive wells.
- Developed and undeveloped acreage.

The following table is a summary of the proved reserves information included in the "Oil and Gas Operations" disclosures following the Notes to Consolidated Financial Statements. Approximately 80 percent of our proved reserves are located in politically stable countries that belong to the Organization for Economic Cooperation and Development. Natural gas reserves are converted to BOE based on a 6:1 ratio: six MCF of natural gas converts to one BOE. See Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance the understanding of the following summary reserves table.

	Millions of Barrels of Oil Equivalent		
Net Proved Reserves at December 31	**2019**	2018	2017
Crude oil			
Consolidated operations	**2,562**	2,533	2,322
Equity affiliates	**73**	78	83
Total Crude Oil	**2,635**	2,611	2,405
Natural gas liquids			
Consolidated operations	**361**	349	354
Equity affiliates	**39**	42	45
Total Natural Gas Liquids	**400**	391	399
Natural gas			
Consolidated operations	**1,209**	1,265	1,267
Equity affiliates	**736**	760	717
Total Natural Gas	**1,945**	2,025	1,984
Bitumen			
Consolidated operations	**282**	236	250
Total Bitumen	**282**	236	250
Total consolidated operations	**4,414**	4,383	4,193
Total equity affiliates	**848**	880	845
Total company	**5,262**	5,263	5,038

Total production of 1,348 MBOED increased 5 percent in 2019 compared with 2018. The increase in total average production primarily resulted from new wells online in the Lower 48; an increased interest in the Western North Slope (WNS) and Greater Kuparuk Area (GKA) of Alaska following acquisitions closed in 2018; and higher production in Norway due to drilling activity and the startup of Aasta Hansteen in December 2018. The increase in production was partly offset by normal field decline and disposition impacts, primarily from the U.K. asset sale in 2019 and non-core asset sales in the Lower 48 during 2018.

Production excluding Libya was 1,305 MBOED in 2019 compared with 1,242 MBOED in 2018, an increase of 63 MBOED or 5 percent. Underlying production, which excludes Libya and the net volume impact from closed dispositions and acquisitions of 51 MBOED in 2019 and 47 MBOED in 2018, is used to measure our ability to grow production organically. Our underlying production grew 5 percent to 1,254 MBOED in 2019 from 1,195 MBOED in 2018.

Our worldwide annual average realized price was $48.78 per BOE in 2019, a decrease of 9 percent compared with $53.88 per BOE in 2018, reflecting weaker marker prices as a result of macroeconomic demand concerns. Our worldwide annual average crude oil price decreased 10 percent, from $68.13 per barrel in 2018 to $60.99 per barrel in 2019. Additionally, our worldwide annual average NGL prices decreased 34 percent, from $30.48 per barrel in 2018 to $20.09 per barrel in 2019. Our worldwide annual average natural gas price decreased 11 percent, from $5.65 per MCF in 2018 to $5.03 per MCF in 2019. Average annual bitumen prices increased 42 percent, from $22.29 per barrel in 2018 to $31.72 per barrel in 2019.

ALASKA

The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas and NGLs. We are the largest crude oil producer in Alaska and have major ownership interests in two of North America's largest oil fields located on Alaska's North Slope: Prudhoe Bay and Kuparuk. We also have a 100 percent interest in the Alpine Field, located on the Western North Slope. Additionally, we are one of Alaska's largest owners of state, federal and fee exploration leases, with approximately 1.32 million net undeveloped acres at year-end 2019. Alaska operations contributed 25 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

			2019		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Greater Prudhoe Area	36.1%	BP	81	4	81
Greater Kuparuk Area	91.4-94.7	ConocoPhillips	86	2	86
Western North Slope	100.0	ConocoPhillips	50	1	51
Total Alaska			217	7	218

Greater Prudhoe Area

The Greater Prudhoe Area includes the Prudhoe Bay Field and five satellite fields, as well as the Greater Point McIntyre Area fields. Prudhoe Bay, the largest oil field on Alaska's North Slope, is the site of a large waterflood and enhanced oil recovery operation, as well as a gas plant which processes natural gas to recover NGLs before reinjection into the reservoir. Prudhoe Bay's satellites are Aurora, Borealis, Polaris, Midnight Sun and Orion, while the Point McIntyre, Niakuk, Raven, Lisburne and North Prudhoe Bay State fields are part of the Greater Point McIntyre Area.

Greater Kuparuk Area

We operate the Greater Kuparuk Area, which consists of the Kuparuk Field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located 40 miles west of Prudhoe Bay. Field installations include three central production facilities which separate oil, natural gas and water, as well as a separate seawater treatment plant. Development drilling at Kuparuk consists of rotary-drilled wells and horizontal multi-laterals from existing well bores utilizing coiled-tubing drilling.

Western North Slope
On the Western North Slope, we operate the Colville River Unit, which includes the Alpine Field and three satellite fields: Nanuq, Fiord and Qannik. Alpine is located 34 miles west of Kuparuk. In 2015, first oil was achieved at Alpine West CD5, a drill site which extends the Alpine reservoir west into the National Petroleum Reserve-Alaska (NPR-A). In 2019, we continued drilling additional wells using the available well slots on this pad.

The Greater Mooses Tooth Unit, the first unit established entirely within the NPR-A, was formed in 2008. In 2017, we began construction in the unit with two drill sites; Greater Mooses Tooth #1 (GMT-1) and Greater Mooses Tooth #2 (GMT-2). GMT-1 achieved first oil in the fourth quarter of 2018 and completed drilling in 2019. We expect first oil from GMT-2 in 2021.

Alaska North Slope Gas
In 2016, we, along with affiliates of Exxon Mobil Corporation, BP p.l.c. and Alaska Gasline Development Corporation (AGDC), a state-owned corporation, completed preliminary FEED technical work for a potential LNG project which would liquefy and export natural gas from Alaska's North Slope and deliver it to market. In 2016, we, along with the affiliates of ExxonMobil and BP, indicated our intention not to progress into the next phase of the project due to changes in the economic environment. AGDC decided to continue on its own. In 2019, affiliates of ExxonMobil and BP agreed to each contribute up to $5 million or approximately one third of AGDC's anticipated costs for full-year 2020. In 2020, AGDC will be focused on permitting efforts, the most important of which is the National Environmental Protection Act process before the FERC. FERC's final milestones are the Publication of Notice of Availability of Final Environmental Impact Statement, which is scheduled for March 6, 2020, and the Issuance of Final Order, which is scheduled for June 4, 2020. AGDC has recently contracted with Fluor Corporation to evaluate cost reduction opportunities in preparation for soliciting partners for the project. We continue to be willing to sell our North Slope gas to the project but do not plan to take an equity position.

Exploration
Appraisal of the Willow Discovery, located in the northeast portion of the NPR-A, continued throughout 2019 with five appraisal wells. In 2020, we will continue appraisal of the Willow Discovery and explore the Harpoon Prospect, located southwest of Willow.

In 2019, we drilled the West Willow-2 well to appraise the 2018 West Willow oil discovery.

In late 2018, we commenced appraisal of the Putu Discovery with a long reach well from existing Alpine CD4 infrastructure. The CD4 appraisal well finished drilling and flow tested in 2019. A supporting injector well was drilled in late 2019 for a 2020 injectivity test.

The Cairn 2S-315 Well was drilled in late 2018 from the 2S drill site on state leases in the Kuparuk River Unit. A long-term flow test was commenced in 2019 and evaluations are ongoing.

A 3-D seismic survey was completed in 2018 over a 250-mile area on state lands. We are currently evaluating this seismic data for future exploration opportunities.

We were successful in the federal lease sale on the North Slope in the fourth quarter of 2019, where we were the high bidder on three tracts for a total of approximately 33,000 net acres.

Acquisitions
In the third quarter of 2019, we completed the Nuna discovery acreage acquisition, expanding the Kuparuk River Unit by 21,000 acres and leveraging legacy infrastructure.

Transportation
We transport the petroleum liquids produced on the North Slope to south central Alaska through an 800-mile pipeline that is part of Trans-Alaska Pipeline System (TAPS). We have a 29.1 percent ownership interest in TAPS, and we also have ownership interests in the Alpine, Kuparuk and Oliktok pipelines on the North Slope.

Our wholly owned subsidiary, Polar Tankers, Inc., manages the marine transportation of our North Slope production, using five company-owned, double-hulled tankers, and charters third-party vessels as necessary. The tankers deliver oil from Valdez, Alaska, primarily to refineries on the west coast of the U.S.

LOWER 48

The Lower 48 segment consists of operations located in the contiguous U.S. and the Gulf of Mexico. Organized into the Gulf Coast and Great Plains business units, we hold 10.4 million net onshore and offshore acres, with a portfolio of conventional production from legacy assets as well as newer production from our low cost of supply, shorter cycle time, resource-rich unconventional plays. Based on 2019 production volumes, the Lower 48 is the company's largest segment and contributed 39 percent of our worldwide liquids production and 22 percent of our natural gas production.

			2019		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Eagle Ford	Various %	Various	174	251	216
Gulf of Mexico	Various	Various	15	11	16
Gulf Coast—Other	Various	Various	3	9	5
Total Gulf Coast			192	271	237
Bakken	Various	Various	82	92	97
Permian Unconventional	Various	Various	40	94	56
Permian Conventional	Various	Various	20	59	30
Anadarko Basin	Various	Various	5	58	14
Wyoming/Uinta	Various	Various	-	36	6
Niobrara*	Various	Various	8	12	11
Total Great Plains			155	351	214
Total Lower 48			347	622	451

**Classified as held-for-sale as of December 31, 2019. See 'Dispositions' below for additional information.*

Onshore
We hold 10.3 million net acres of onshore conventional and unconventional acreage in the Lower 48, the majority of which is either held by production or owned by the company. Our unconventional holdings total approximately 1.7 million net acres in the following areas:

- 610,000 net acres in the Bakken, located in North Dakota and eastern Montana.
- 234,000 net acres in Central Louisiana, where we recently announced our intention to discontinue exploration activities.
- 201,000 net acres in the Eagle Ford, located in South Texas.
- 167,000 net acres in the Permian, located in West Texas and southeastern New Mexico.
- 98,000 net acres in the Niobrara, located in northeastern Colorado.
- 363,000 net acres in other areas with unconventional potential.

The majority of our 2019 onshore production originated from the Big 3—Eagle Ford, Bakken and Permian Unconventional. Onshore activities in 2019 were centered mostly on continued development of assets, with an emphasis on areas with low cost of supply, particularly in growing unconventional plays. Our major focus areas in 2019 included the following:

- Eagle Ford—The Eagle Ford continued full-field development in 2019. We operated seven rigs on average in 2019, resulting in 155 operated wells drilled and 166 operated wells brought online. Production increased 16 percent in 2019 compared with 2018, averaging 216 MBOED and 186 MBOED, respectively.
- Bakken—We operated an average of three rigs during the year in the Bakken and participated in additional development activities operated by co-venturers. We continued our pad drilling with 62 operated wells drilled during the year and 44 operated wells brought online. Production increased 15 percent in 2019 compared with 2018, averaging 97 MBOED and 84 MBOED, respectively.
- Permian Basin—The Permian Basin is a combination of legacy conventional and unconventional assets. We operated an average of three rigs during the year in the Permian Basin, resulting in 29 operated wells drilled and 35 operated wells brought online. The Permian Basin produced 86 MBOED in 2019, increasing 30 percent compared with 2018, including 56 MBOED of unconventional production.

Gulf of Mexico
At year-end 2019, our portfolio of producing properties in the Gulf of Mexico totaled approximately 60,000 net acres. A majority of the production consists of three fields operated by co-venturers:

- 15.9 percent nonoperated working interest in the unitized Ursa Field located in the Mississippi Canyon Area.
- 15.9 percent nonoperated working interest in the Princess Field, a northern subsalt extension of the Ursa Field.
- 12.4 percent nonoperated working interest in the unitized K2 Field, comprised of seven blocks in the Green Canyon Area.

Dispositions
We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from Qatar Liquefied Gas Company Limited (3) (QG3). We previously held a 12.4 percent interest in Golden Pass LNG Terminal and Golden Pass Pipeline, but we sold those interests in the second quarter of 2019 while retaining the basic use agreements.

In the fourth quarter of 2019, we completed the sale of our interests in the Magnolia Field in the Gulf of Mexico. Production from this disposed asset was less than one MBOED in 2019.

In the fourth quarter of 2019, we entered into an agreement to sell our interests in the Niobrara, with an anticipated closing date in the first quarter of 2020. Production from the interests to be disposed was approximately 11 MBOED in 2019.

In January 2020, we entered into an agreement to sell our interests in certain non-core properties for $186 million, plus customary adjustments. The assets met the held for sale criteria in January 2020 and the transaction is expected to be completed in the first quarter of 2020. This disposition will not have a significant impact on Lower 48 production.

For additional information on these transactions, see Note 5—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements.

Exploration
Our exploration focus is on onshore unconventional plays, which in 2019 included the Delaware in the Permian Basin, and the Eagle Ford in south Texas. In the third quarter of 2019, we announced our decision to discontinue exploration activities in the Central Louisiana Austin Chalk.

Facilities

- Lost Cabin Gas Plant—We operate and own a 46 percent interest in the Lost Cabin Gas Plant, a 246 MMCFD capacity natural gas processing facility in Lysite, Wyoming. The plant is currently operating at less than capacity due to a fire in December 2018. Restoration efforts are ongoing and anticipated to be completed in the second half of 2020. The expected production loss in 2020 is immaterial to the segment.
- Helena Condensate Processing Facility—We operate and own the Helena Condensate Processing Facility, a 110 MBD condensate processing plant located in Kenedy, Texas.
- Sugarloaf Condensate Processing Facility—We operate and own an 87.5 percent interest in the Sugarloaf Condensate Processing Facility, a 30 MBD condensate processing plant located near Pawnee, Texas.
- Bordovsky Condensate Processing Facility—We operate and own the Bordovsky Condensate Processing Facility, a 15 MBD condensate processing plant located in Kenedy, Texas.

CANADA

Our Canadian operations mainly consist of the Surmont oil sands development in Alberta and the liquids-rich Montney unconventional play in British Columbia. In 2019, operations in Canada contributed 7 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

			2019			
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Bitumen MBD	Total MBOED
Average Daily Net Production						
Surmont	50.0 %	ConocoPhillips	-	-	60	60
Montney	100.0	ConocoPhillips	1	9	-	3
Total Canada			1	9	60	63

Surmont
Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called SAGD, whereby steam is injected into the reservoir, effectively liquefying the heavy bitumen, which is recovered and pumped to the surface for further processing. We hold approximately 0.6 million net acres of land in the Athabasca Region of northeastern Alberta.

The Surmont oil sands leases are located approximately 35 miles south of Fort McMurray, Alberta. Surmont is a 50/50 joint venture with Total S.A. The second phase of the Surmont Project achieved first production in 2015 and reached peak production in 2018. We are focused on structurally lowering costs, reducing GHG intensity and optimizing asset performance.

The Alberta government imposed a production curtailment impacting the industry beginning in January 2019. The curtailment measure, which impacted our annualized average production by 3 MBOED in 2019, is intended to strengthen the WCS differential to WTI at Hardisty. The curtailment program is established and administered by the Alberta Energy Regulator under the *Curtailment Rules* regulation, which is currently set to expire on December 31, 2020.

Montney
We hold approximately 151,000 net acres in the emerging unconventional Montney play in northeast British Columbia. Our Montney activity in 2019 included drilling 16 horizontal wells, completing 14 horizontal wells and acquiring approximately 6,000 additional net acres. Production from our 2019 drilling program commenced in February 2020 following the completion of third-party offtake facilities.

Appraisal drilling and completions activity will continue in 2020 to further explore the area’s resource potential.

Exploration
Our primary exploration focus is assessing our Montney onshore unconventional acreage in Western Canada. Additionally, we have exploration acreage in the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands.

EUROPE AND NORTH AFRICA

The Europe and North Africa segment consisted of operations in Norway, Libya and the U.K. and exploration activities in Norway and Libya. In 2019, operations in Europe and North Africa contributed 16 percent of our worldwide liquids production and 17 percent of natural gas production.

Norway

			2019		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Greater Ekofisk Area	35.1%	ConocoPhillips	50	44	57
Heidrun	24.0	Equinor	14	29	19
Alvheim	20.0	Aker BP	10	12	12
Visund	9.1	Equinor	4	46	12
Aasta Hansteen	10.0	Equinor	-	64	11
Troll	1.6	Equinor	2	49	10
Other	Various	Equinor	8	10	10
Total Norway			88	254	131

The Greater Ekofisk Area is located approximately 200 miles offshore Stavanger, Norway, in the North Sea, and comprises three producing fields: Ekofisk, Eldfisk and Embla. Crude oil is exported to Teesside, England, and the natural gas is exported to Emden, Germany. The Ekofisk and Eldfisk fields consist of several production platforms and facilities, including the Ekofisk South and Eldfisk II developments. Continued development drilling in the Greater Ekofisk Area is expected to contribute additional production over the coming years, as additional wells come online.

The Heidrun Field is located in the Norwegian Sea. Produced crude oil is stored in a floating storage unit and exported via shuttle tankers. Part of the natural gas is currently injected into the reservoir for optimization of crude oil production, some gas is transported for use as feedstock in a methanol plant in Norway, in which we own an 18 percent interest, and the remainder is transported to Europe via gas processing terminals in Norway.

The Alvheim Field is located in the northern part of the North Sea near the border with the U.K. sector, and consists of a FPSO vessel and subsea installations. Produced crude oil is exported via shuttle tankers, and natural gas is transported to the Scottish Area Gas Evacuation (SAGE) Terminal at St. Fergus, Scotland, through the SAGE Pipeline.

Visund is an oil and gas field located in the North Sea and consists of a floating drilling, production and processing unit, and subsea installations. Crude oil is transported by pipeline to a nearby third-party field for storage and export via tankers. The natural gas is transported to a gas processing plant at Kollsnes, Norway, through the Gassled transportation system.

Aasta Hansteen is located in the Norwegian Sea and achieved first production in December 2018. Produced condensate is loaded onto shuttle tankers and transported to market. Gas is transported through the Polarled gas pipeline to the onshore Nyhamna processing plant for final processing prior to export to market.

The Troll Field lies in the northern part of the North Sea and consists of the Troll A, B and C platforms. The natural gas from Troll A is transported to Kollsnes, Norway. Crude oil from floating platforms Troll B and Troll C is transported to Mongstad, Norway, for storage and export.

We also have varying ownership interests in two other producing fields in the Norway sector of the North Sea.

Exploration
In 2019, we operated the Busta and Enniberg exploration wells in Block 25/7 in the North Sea. The Busta well encountered hydrocarbons and will be evaluated for future appraisal consideration. The Enniberg well encountered insufficient hydrocarbons and was expensed as a dry hole in 2019. We also participated in the Canela exploration well in the Heidrun area of the Norwegian Sea. The well encountered hydrocarbons and will be further evaluated to determine commerciality. In 2019, we were awarded two new exploration licenses; PL1001 and PL1009; and one acreage addition, PL782SD.

Transportation
We own a 35.1 percent interest in the Norpipe Oil Pipeline System, a 220-mile pipeline which carries crude oil from Ekofisk to a crude oil stabilization and NGLs processing facility in Teesside, England.

United Kingdom

			2019		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Britannia Satellites*	26.3–93.8%	ConocoPhillips	7	55	16
J-Area	32.5–36.5	ConocoPhillips	6	38	12
Britannia	58.7	ConocoPhillips	2	49	10
East Irish Sea	100.0	Spirit Energy	-	48	8
Clair	7.5	BP	4	1	4
Other	Various	Various	-	2	-
Total United Kingdom			19	193	50

**Includes the Chevron-operated Alder Field, ConocoPhillips equity interest was 26.3 percent.*

On September 30, 2019, we completed the sale of two ConocoPhillips U.K. subsidiaries to Chrysaor E&P Limited, including all of our producing assets in the U.K. Annualized average production from the assets sold was 50 MBOED in 2019. For additional information on this transaction, see Note 5—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements.

We retained our Teesside, England oil terminal, where we are the operator and have a 40.25 percent ownership interest, to support our Norway operations.

Libya

			2019		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Waha Concession	16.3 %	Waha Oil Co.	38	31	43
Total Libya			38	31	43

The Waha Concession consists of multiple concessions and encompasses nearly 13 million gross acres in the Sirte Basin. Our production operations in Libya and related oil exports have periodically been interrupted over the last several years due to the shutdown of the Es Sider crude oil export terminal. In 2019, we had 19 crude liftings from Es Sider. The number of crude liftings from the Es Sider crude oil export terminal in 2020 is uncertain due to civil unrest. In January 2020, we declared Force Majeure to our crude shippers following the blockade of the Es Sider crude oil export terminal and the declaration of Force Majeure by the National Oil Corporation of Libya.

ASIA PACIFIC AND MIDDLE EAST

The Asia Pacific and Middle East segment has exploration and production operations in China, Indonesia, Malaysia and Australia and producing operations in Qatar and Timor-Leste. In 2019, operations in the Asia Pacific and Middle East segment contributed 13 percent of our worldwide liquids production and 60 percent of natural gas production.

Australia and Timor-Leste

			2019		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Australia Pacific LNG	37.5%	ConocoPhillips/ Origin Energy	-	679	113
Bayu-Undan*	56.9	ConocoPhillips	10	194	43
Athena/Perseus*	50.0	ExxonMobil	-	31	5
Total Australia and Timor-Leste			10	904	161

**This asset is held-for-sale as of December 31, 2019. See Note 5—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements, for additional information.*

Australia Pacific LNG
Australia Pacific LNG Pty Ltd (APLNG), our joint venture with Origin Energy Limited and China Petrochemical Corporation (Sinopec), is focused on producing CBM from the Bowen and Surat basins in Queensland, Australia, to supply the domestic gas market and convert the CBM into LNG for export. Origin operates APLNG's upstream production and pipeline system, and we operate the downstream LNG facility, located on Curtis Island near Gladstone, Queensland, as well as the LNG export sales business.

We operate two fully subscribed 4.5-million-metric-tonnes-per-year LNG trains. Approximately 3,900 net wells are ultimately expected to supply both the LNG sales contracts and domestic gas market. The wells are supported by gathering systems, central gas processing and compression stations, water treatment facilities, and an export pipeline connecting the gas fields to the LNG facilities. The LNG is being sold to Sinopec under 20-year sales agreements for 7.6 million metric tonnes of LNG per year, and Japan-based Kansai Electric Power Co., Inc. under a 20-year sales agreement for approximately 1 million metric tonnes of LNG per year.

As of December 31, 2019, APLNG has an outstanding balance of $6.7 billion on a $8.5 billion project finance facility. In late 2018 and early 2019, APLNG successfully refinanced $4.6 billion of the project finance facility through three separate transactions, which added lower cost United States Private Placement (USPP) bond and commercial bank facilities. In conjunction with these transactions, APLNG made voluntary repayments of $2.2 billion to a syndicate of Australian and international commercial banks and fully extinguished $2.4 billion of financing from the Export-Import Bank of China. Project finance interest payments are bi-annual, concluding September 2030.

For additional information, see Note 3—Variable Interest Entities, Note 6—Investments, Loans and Long-Term Receivables and Note 12—Guarantees, in the Notes to Consolidated Financial Statements.

Bayu-Undan
The Bayu-Undan gas condensate field is located in the Timor Sea Joint Petroleum Development Area between Timor-Leste and Australia. We also operate and own a 56.9 percent interest in the associated Darwin LNG Facility, located at Wickham Point, Darwin.

The Bayu-Undan natural gas recycle facility processes wet gas; separates, stores and offloads condensate, propane and butane; and re-injects dry gas back into the reservoir. In addition, a 310-mile natural gas pipeline connects the facility to the 3.5-million-metric-tonnes-per-year capacity Darwin LNG Facility. Produced natural gas is piped to the Darwin LNG Plant, where it is converted into LNG before being transported to international markets. In 2019, we sold 133 billion gross cubic feet of LNG primarily to utility customers in Japan.

Athena/Perseus
The Athena production license (WA-17-L) in which we had a 50 percent working interest is located offshore Western Australia and our entitlement to production ended in the fourth quarter of 2019. Annualized average production from this license was five MBOED in 2019.

Exploration
We operate three exploration permits in the Browse Basin, offshore northwest Australia, in which we own a 40 percent interest in permits WA-315-P, WA-398-P and TP 28, of the Greater Poseidon Area. Phase I of the Browse Basin drilling campaign resulted in three discoveries in the Greater Poseidon Area and Phase II resulted in five additional discoveries. All wells have been plugged and abandoned.

We operate two retention leases in the Bonaparte Basin, offshore northern Australia, where we own a 37.5 percent interest in the Barossa and Caldita discoveries. In April 2018, Barossa entered the FEED phase of development which continued through 2019. During the FEED phase, costs and the technical definition for the project will be finalized, gas and condensate sales agreements progressed, and access arrangements negotiated with the owners of the Darwin LNG Facility and Bayu-Darwin Pipeline.

In December 2019, we entered into an agreement with 3D Oil to acquire a 75 percent interest and operatorship of an offshore Tasmanian Permit located in the Otway Basin. The farm-in agreement is conditional upon the agreement and signing of a JOA by both parties and required government approvals. We plan to conduct a 3D seismic survey in the second half of 2020. This activity is excluded from the dispositions discussed below.

Dispositions
In the second quarter of 2019, we completed the sale of our 30 percent interest in the Greater Sunrise Fields to the government of Timor-Leste.

In October 2019, we entered into an agreement to sell the subsidiaries that hold our Australia-West assets and operations to Santos with an expected completion date in the first quarter of 2020, subject to regulatory approvals and other specific conditions precedent. These subsidiaries hold our 37.5 percent interest in the Barossa Project and Caldita Field, our 56.9 percent interest in the Darwin LNG Facility and Bayu-Undan Field, our 40 percent interest in the Greater Poseidon Fields, and our 50 percent interest in the Athena Field. Production associated with the Australia-West assets to be sold was 48 MBOED in 2019.

For additional information on these transactions, see Note 5—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements.

Indonesia

	Interest	Operator	2019 Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
South Sumatra	54 %	ConocoPhillips	2	321	56
Total Indonesia			2	321	56

During 2019, we operated three PSCs in Indonesia: the Corridor Block and South Jambi "B," both located in South Sumatra, and Kualakurun in Central Kalimantan. Currently, we have production from the Corridor Block.

South Sumatra
The Corridor PSC consists of two oil fields and seven producing natural gas fields. Natural gas is supplied from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets in Singapore, Batam and West Java. In 2019, we were awarded a 20-year extension, with new terms, of the Corridor PSC. Under these terms, we retain a majority interest and continue as operator for at least three years after 2023 and retain a participating interest until 2043.

Production from the South Jambi "B" PSC has reached depletion and field development has been suspended. This PSC expired on January 26, 2020 and has been returned to the Government of Indonesia.

Exploration
We hold a 60 percent working interest in the Kualakurun PSC. After completion of prospect evaluation, we and the other joint venture partners decided to relinquish all of the remaining acreage to the Government of Indonesia.

Transportation
We are a 35 percent owner of a consortium company that has a 40 percent ownership in PT Transportasi Gas Indonesia, which owns and operates the Grissik to Duri and Grissik to Singapore natural gas pipelines.

China

	Interest	Operator	2019 Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Penglai	49.0 %	CNOOC	29	-	29
Panyu	24.5	CNOOC	6	-	6
Total China			35	-	35

Penglai
The Penglai 19-3, 19-9 and 25-6 fields are located in Bohai Bay Block 11/05 and are in various stages of development.

As part of further development of the Penglai 19-9 Field, the wellhead platform J Project achieved first production in 2016. This project will include 62 wells, 57 of which have been completed and brought online through December 2019.

The Penglai 19-3/19-9 Phase 3 Project consists of three new wellhead platforms and a central processing platform. First oil from Phase 3 was achieved in 2018 for two of the platforms, with the third platform planned to come online in the second quarter of 2020. This project could include up to 186 wells, 42 of which have been completed and brought online through December 2019.

In December 2018, we sanctioned the Penglai 25-6 Phase 4A Project. This project consists of one new wellhead platform and anticipates 62 new wells. First production is expected in 2021.

Panyu
Our production license for Panyu 4-2, 5-1 and 11-6 located in Block 15/34 in the South China Sea expired in September 2019. Annualized average production from these licenses were six MBOED in 2019.

We still have a license for Panyu 4-1 in Block 15/34 and are evaluating this area for potential development.

Exploration
Exploration activities in the Bohai Penglai Field during 2019 consisted of two successful appraisal wells, a full-field 3-D seismic program covering existing and future development opportunities, and an infill compressive seismic imaging (CSI) survey to improve imaging beneath the gas cloud in support of future development projects. In Block 15/34, one exploration well was drilled in the Panyu 4-1E prospect and was expensed as a dry hole.

Malaysia

			2019		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Gumusut	29.0 %	Shell	23	-	23
Kebabangan (KBB)	30.0	KPOC	3	91	18
Malikai	35.0	Shell	15	-	15
Siakap North-Petai	21.0	PTTEP	1	-	1
Total Malaysia			42	91	57

We have varying stages of exploration, development and production activities across 2.2 million net acres in Malaysia, with working interests in six PSCs. Three of these PSCs are located off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster (KBBC). We operated three exploration blocks, Block SK304, Block SK313 and Block WL4-00, off the eastern Malaysian state of Sarawak.

Block J
Gumusut
First production from the Gumusut Field occurred from an early production system in 2012. Production from a permanent, semi-submersible Floating Production System was achieved in 2014. We currently have a 29 percent working interest in the Gumusut Field following the redetermination of the Block J and Block K Malaysia Unit in 2017. Gumusut Phase 2 first oil was achieved in 2019.

KBBC
The KBBC PSC grants us a 30 percent working interest in the KBB, Kamunsu East and Kamunsu East Upthrown Canyon gas and condensate fields.

KBB
First production from the KBB gas field was achieved in 2014. During 2019, KBB tied-in to a nearby third-party floating LNG vessel which provided increased gas offtake capacity. Production in 2020 is anticipated to be impacted between 15 to 20 MBOED due to the rupture of a third-party pipeline, in January 2020, which

carries gas production from the KBB gas field to market. The extent of the required pipeline repairs, and the amount of time required to return this pipeline to full service is still being evaluated.

Kamunsu East
Development options for the Kamunsu East gas field are being evaluated.

Block G
Malikai
We hold a 35 percent working interest in Malikai. This field achieved first production in December 2016 via the Malikai Tension Leg Platform, ramping to peak production in 2018. The KMU-1 exploration well was completed and started producing through the Malikai platform in 2018. Malikai Phase 2 development, a 6-well drilling campaign that will commence in 2020, reached a final investment decision in late 2019.

Siakap North-Petai
We hold a 21 percent working interest in the unitized Siakap North-Petai oil field.

Exploration
In 2016, we entered into a farm-in agreement to acquire a 50 percent working interest in Block SK 313, a 1.4 million gross-acre exploration block offshore Sarawak, with an effective date of January 2017. Following completion of the Sadok-1 exploration well in January 2017, we assumed operatorship of the block from PETRONAS and completed a 3-D seismic survey. We have no plans for further exploration activity in this block.

In 2017, we were awarded operatorship and a 50 percent working interest in Block WL4-00, which included the existing Salam-1 oil discovery and encompassed 0.6 million gross acres. In 2018 and 2019, two exploration and two appraisal wells were drilled, resulting in oil discoveries under evaluation at Salam and Benum, while two Patawali wells were expensed as dry holes in 2019.

In 2018, we were awarded a 50 percent working interest and operatorship of Block SK304 encompassing 2.1 million gross acres offshore Sarawak. We acquired 3-D seismic over the acreage and completed processing of this data in 2019.

The Gemilang-1 exploration well in Block J was completed in late 2018. Development options are being evaluated.

Qatar

			2019		
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
QG3	30.0 %	Qatargas Operating Company Limited	21	373	83
Total Qatar			21	373	83

QG3 is an integrated development jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). QG3 consists of upstream natural gas production facilities, which produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar's North Field over a 25-year life, in addition to a 7.8 million gross tonnes-per-year LNG facility. LNG is shipped in leased LNG carriers destined for sale globally.

QG3 executed the development of the onshore and offshore assets as a single integrated development with Qatargas 4 (QG4), a joint venture between Qatar Petroleum and Royal Dutch Shell plc. This included the joint development of offshore facilities situated in a common offshore block in the North Field, as well as the construction of two identical LNG process trains and associated gas treating facilities for both the QG3 and QG4 joint ventures. Production from the LNG trains and associated facilities is combined and shared.

OTHER INTERNATIONAL

The Other International segment includes exploration activities in Colombia, Chile and Argentina and contingencies associated with prior operations.

Colombia
We have an 80 percent operated interest in the Middle Magdalena Basin Block VMM-3. The block extends over approximately 67,000 net acres and contains the Picoplata-1 Well, which completed drilling in 2015 and testing in 2017. Plug and abandonment activity started during 2018 and completed in 2019. In addition, we have an 80 percent working interest in the VMM-2 Block which extends over approximately 58,000 net acres and is contiguous to the VMM-3 Block. As part of a case brought forward by environmental groups, the Highest Administrative Court granted a preliminary injunction temporarily suspending hydraulic fracturing activities until the substance of the case is decided. As a result, ConocoPhillips filed two separate Force Majeure requests before the competent authority for both blocks, which were granted.

Chile
We have a 49 percent interest in the Coiron Block located in the Magallanes Basin in southern Chile.

Argentina
In January 2019, we secured a 50 percent nonoperated interest in the El Turbio Este Block, within the Austral Basin in southern Argentina. In 2019, we acquired and processed 3-D seismic covering approximately 500 square miles, with evaluation of the data ongoing.

In November 2019, we acquired interests in two nonoperated blocks in the Neuquén Basin targeting the Vaca Muerta play. We have a 50 percent interest in the Bandurria Norte Block and a 45 percent interest in the Aguada Federal Block. In Bandurria Norte, one vertical and four horizontal wells were tested and shut-in during 2019. In Aguada Federal, two horizontal wells were being tested at the end of the year.

Venezuela and Ecuador
For discussion of our contingencies in Venezuela and Ecuador, see Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

OTHER

Marketing Activities
Our Commercial organization manages our worldwide commodity portfolio, which mainly includes natural gas, crude oil, bitumen, NGLs and LNG. Marketing activities are performed through offices in the U.S., Canada, Europe and Asia. In marketing our production, we attempt to minimize flow disruptions, maximize realized prices and manage credit-risk exposure. Commodity sales are generally made at prevailing market prices at the time of sale. We also purchase and sell third-party volumes to better position the company to satisfy customer demand while fully utilizing transportation and storage capacity.

Natural Gas
Our natural gas production, along with third-party purchased gas, is primarily marketed in the U.S., Canada, Europe and Asia. Our natural gas is sold to a diverse client portfolio which includes local distribution companies; gas and power utilities; large industrials; independent, integrated or state-owned oil and gas

companies; as well as marketing companies. To reduce our market exposure and credit risk, we also transport natural gas via firm and interruptible transportation agreements to major market hubs.

Crude Oil, Bitumen and Natural Gas Liquids
Our crude oil, bitumen and NGL revenues are derived from production in the U.S., Canada, Australia, Asia, Africa and Europe. These commodities are primarily sold under contracts with prices based on market indices, adjusted for location, quality and transportation.

LNG
LNG marketing efforts are focused on equity LNG production facilities located in Australia and Qatar. LNG is primarily sold under long-term contracts with prices based on market indices.

Energy Partnerships
Marine Well Containment Company (MWCC)
We are a founding member of the MWCC, a non-profit organization formed in 2010, which provides well containment equipment and technology in the deepwater U.S. Gulf of Mexico. MWCC's containment system meets the U.S. Bureau of Safety and Environmental Enforcement requirements for a subsea well containment system that can respond to a deepwater well control incident in the U.S. Gulf of Mexico. For additional information, see Note 3—Variable Interest Entities, in the Notes to Consolidated Financial Statements.

Subsea Well Response Project (SWRP)
In 2011, we, along with several leading oil and gas companies, launched the SWRP, a non-profit organization based in Stavanger, Norway, which was created to enhance the industry's capability to respond to international subsea well control incidents. Through collaboration with Oil Spill Response Limited, a non-profit organization in the U.K., subsea well intervention equipment is available for the industry to use in the event of a subsea well incident. This complements the work being undertaken in the U.S. by MWCC and provides well capping and containment capability outside the U.S.

Oil Spill Response Removal Organizations (OSROs)
We maintain memberships in several OSROs across the globe as a key element of our preparedness program in addition to internal response resources. Many of the OSROs are not-for-profit cooperatives owned by the member companies wherein we may actively participate as a member of the board of directors, steering committee, work group or other supporting role. Globally, our primary OSRO is Oil Spill Response Ltd. based in the U.K., with facilities in several other countries and the ability to respond anywhere in the world. In North America, our primary OSROs include the Marine Spill Response Corporation for the continental United States and Alaska Clean Seas and Ship Escort/Response Vessel System for the Alaska North Slope and Prince William Sound, respectively. Internationally, we maintain memberships in various regional OSROs including the Norwegian Clean Seas Association for Operating Companies, Australian Marine Oil Spill Center and Petroleum Industry of Malaysia Mutual Aid Group.

Technology
We have several technology programs that improve our ability to develop unconventional reservoirs, produce heavy oil economically with less emissions, improve the efficiency of our exploration program, increase recoveries from our legacy fields, and implement sustainability measures.

Our Optimized Cascade® LNG liquefaction technology business continues to be successful with the demand for new LNG plants. The technology has been licensed for use in 26 LNG trains around the world, with feasibility studies ongoing for additional trains.

RESERVES

We have not filed any information with any other federal authority or agency with respect to our estimated total proved reserves at December 31, 2019. No difference exists between our estimated total proved reserves for year-end 2018 and year-end 2017, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2019.

DELIVERY COMMITMENTS

We sell crude oil and natural gas from our producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 1.1 trillion cubic feet of natural gas, including approximately 75 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 172 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2030. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using PUDs and spot market purchases to fulfill any remaining commitments. See the disclosure on "Proved Undeveloped Reserves" in the "Oil and Gas Operations" section following the Notes to Consolidated Financial Statements, for information on the development of PUDs.

COMPETITION

We compete with private, public and state-owned companies in all facets of the E&P business. Some of our competitors are larger and have greater resources. Each of our segments is highly competitive, with no single competitor, or small group of competitors, dominating.

We compete with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, NGLs and natural gas in an efficient, cost-effective manner. Based on statistics published in the September 2, 2019, issue of the *Oil and Gas Journal*, we were the third-largest U.S.-based oil and gas company in worldwide natural gas and liquids production and worldwide liquids reserves in 2018. We deliver our production into the worldwide commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with portfolio management; and safely operating oil and gas producing properties.

GENERAL

At the end of 2019, we held a total of 942 active patents in 50 countries worldwide, including 371 active U.S. patents. During 2019, we received 64 patents in the U.S. and 90 foreign patents. Our products and processes generated licensing revenues of $69 million related to activity in 2019. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

Health, Safety and Environment
Our HSE organization provides tools and support to our business units and staff groups to help them ensure world class HSE performance. The framework through which we safely manage our operations, the HSE Management System Standard, emphasizes process safety, risk management, emergency preparedness and environmental performance, with an intense focus on process and occupational safety. In support of the goal of zero incidents, HSE milestones and criteria are established annually to drive strong safety and environmental performance. Progress toward these milestones and criteria are measured and reported. HSE audits are conducted on business functions periodically, and improvement actions are established and tracked to completion. We have designed processes relating to sustainable development in our economic, environmental and social performance. Our processes, related tools and requirements focus on water, biodiversity and climate change, as well as social and stakeholder issues.

The environmental information contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 60 through 65 under the captions "Environmental" and "Climate Change" is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2019 and those expected for 2020 and 2021.

Website Access to SEC Reports
Our internet website address is *www.conocophillips.com*. Information contained on our internet website is not part of this report on Form 10-K.

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. Alternatively, you may access these reports at the SEC's website at *www.sec.gov*.

Item 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. These risk factors are not the only risks we face. Our business could also be affected by additional risks and uncertainties not currently known to us or that we currently consider to be immaterial. If any of these risks were to occur, our business, operating results and financial condition, as well as the value of an investment in our common stock could be adversely affected.

Our operating results, our future rate of growth and the carrying value of our assets are exposed to the effects of changing commodity prices.

Prices for crude oil, bitumen, natural gas, NGLs and LNG can fluctuate widely. Brent crude oil prices averaged $64 per barrel in 2019, ranging from a low of $53 per barrel in January to a high of almost $75 per barrel in April. Given volatility in commodity price drivers and the worldwide political and economic environment generally, as well as increased uncertainty generated by recent (and potential future) armed hostilities in various oil-producing regions around the globe, price trends may continue to be volatile. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil, bitumen, natural gas, NGLs and LNG. The factors influencing these prices are beyond our control.

Lower crude oil, bitumen, natural gas, NGL and LNG prices may have a material adverse effect on our revenues, operating income, cash flows and liquidity, and may also affect the amount of dividends we elect to declare and pay on our common stock and the amount of shares we elect to acquire as part of the share repurchase program and the timing of such acquisitions. Lower prices may also limit the amount of reserves we can produce economically, adversely affecting our proved reserves, reserve replacement ratio and accelerating the reduction in our existing reserve levels as we continue production from upstream fields.

Significant reductions in crude oil, bitumen, natural gas, NGLs and LNG prices could also require us to reduce our capital expenditures, impair the carrying value of our assets or discontinue the classification of certain assets as proved reserves. In the past three years, we recognized several impairments, which are described in Note 9—Impairments and the "APLNG" section of Note 6—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements. If commodity prices remain low relative to their historic levels, and as we continue to optimize our investments and exercise capital flexibility, it is reasonably likely we will incur future impairments to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method and unproved properties. Although it is not reasonably practicable to quantify the impact of any future impairments at this time, our results of operations could be adversely affected as a result.

Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.

Dividends are authorized and determined by our Board of Directors in its sole discretion and depend upon a number of factors, including:

- Cash available for distribution.
- Our results of operations and anticipated future results of operations.
- Our financial condition, especially in relation to the anticipated future capital needs of our properties.
- The level of distributions paid by comparable companies.
- Our operating expenses.
- Other factors our Board of Directors deems relevant.

We expect to continue to pay quarterly dividends to our stockholders; however, our Board of Directors may reduce our dividend or cease declaring dividends at any time, including if it determines that our net cash provided by operating activities, after deducting capital expenditures and investments, are not sufficient to pay our desired levels of dividends to our stockholders or to pay dividends to our stockholders at all.

Additionally, as of December 31, 2019, $5.4 billion of repurchase authority remained of the $15 billion share repurchase program our Board of Directors had authorized. In February, 2020, our Board of Directors approved an increase to our repurchase authorization from $15 billion to $25 billion, to support our plan for future share repurchases. Our share repurchase program does not obligate us to acquire a specific number of shares during any period, and our decision to commence, discontinue or resume repurchases in any period will depend on the same factors that our Board of Directors may consider when declaring dividends, among others.

Any downward revision in the amount of dividends we pay to stockholders or the number of shares we purchase under our share repurchase program could have an adverse effect on the market price of our common stock.

We may need additional capital in the future, and it may not be available on acceptable terms.

We have historically relied primarily upon cash generated by our operations to fund our operations and strategy; however, we have also relied from time to time on access to the debt and equity capital markets for funding. There can be no assurance that additional debt or equity financing will be available in the future on acceptable terms, or at all. In addition, although we anticipate we will be able to repay our existing indebtedness when it matures or in accordance with our stated plans, there can be no assurance we will be able to do so. Our ability to obtain additional financing, or refinance our existing indebtedness when it matures or in accordance with our plans, will be subject to a number of factors, including market conditions, our operating performance, investor sentiment and our ability to incur additional debt in compliance with agreements governing our then-outstanding debt. If we are unable to generate sufficient funds from operations or raise additional capital for any reason, our business could be adversely affected.

In addition, we are regularly evaluated by the major rating agencies based on a number of factors, including our financial strength and conditions affecting the oil and gas industry generally. We and other industry companies have had their ratings reduced in the past due to negative commodity price outlooks. Any downgrade in our credit rating or announcement that our credit rating is under review for possible downgrade could increase the cost associated with any additional indebtedness we incur.

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. Market speculation about the credit quality of these counterparties, or their ability to continue performing on their existing obligations, may also exacerbate any operational difficulties or liquidity issues they are experiencing, particularly as it relates to other companies in the oil and gas industry as a result of the volatility in commodity prices. Any default by any of our counterparties may result in our inability to perform our obligations under agreements we have made with third parties or may otherwise adversely affect our business or results of operations. In addition, 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 may also be forced to incur additional costs as we attempt to enforce any rights we have against a defaulting counterparty, which could further adversely impact our results of operations.

In particular, in August 2018, we entered into a settlement agreement with Petróleos de Venezuela, S.A. (PDVSA) providing for the payment of approximately $2 billion over a five-year period in connection with an arbitration award issued by the International Chamber of Commerce (ICC) Tribunal in favor of ConocoPhillips on a contractual dispute arising from Venezuela’s expropriation of our interests in the Petrozuata and Hamaca heavy oil ventures and other pre-expropriation fiscal measures. We collected approximately $0.8 billion of the $2.0 billion settlement in 2018 and 2019. PDVSA has defaulted on its remaining payment obligations under this agreement, we are therefore now forced to incur additional costs as we seek to recover any unpaid amounts under the agreement.

Unless we successfully add to our existing proved reserves, our future crude oil, bitumen, natural gas and NGL production will decline, resulting in an adverse impact to our business.

The rate of production from upstream fields generally declines as reserves are depleted. If we do not conduct successful exploration and development activities, or, through engineering studies, optimize production performance or identify additional or secondary recovery reserves, our proved reserves will decline materially as we produce crude oil, bitumen, natural gas and NGLs, and our business will experience reduced cash flows and results of operations. Any cash conservation efforts we may undertake as a result of commodity price declines may further limit our ability to replace depleted reserves.

The exploration and production of oil and gas is a highly competitive industry.

The exploration and production of crude oil, bitumen, natural gas and NGLs is a highly competitive business. We compete with private, public and state-owned companies in all facets of the exploration and production business, including to locate and obtain new sources of supply and to produce oil, bitumen, natural gas and NGLs in an efficient, cost-effective manner. Some of our competitors are larger and have greater resources than we do or may be willing to incur a higher level of risk than we are willing to incur to obtain potential sources of supply. If we are not successful in our competition for new reserves, our financial condition and results of operations may be adversely affected.

Any material change in the factors and assumptions underlying our estimates of crude oil, bitumen, natural gas and NGL reserves could impair the quantity and value of those reserves.

Our proved reserve information included in this annual report represents management's best estimates based on assumptions, as of a specified date, of the volumes to be recovered from underground accumulations of crude oil, bitumen, natural gas and NGLs. Such volumes cannot be directly measured and the estimates and underlying assumptions used by management are subject to substantial risk and uncertainty. Any material changes in the factors and assumptions underlying our estimates of these items could result in a material negative impact to the volume of reserves reported or could cause us to incur impairment expenses on property associated with the production of those reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation.

We expect to continue to incur substantial capital expenditures and operating costs as a result of our compliance with existing and future environmental laws and regulations.

Our business is subject to numerous laws and regulations relating to the protection of the environment, which are expected to continue to have an increasing impact on our operations in the U.S. and in other countries in which we operate. For a description of the most significant of these environmental laws and regulations, see the "Contingencies—Environmental" section of Management's Discussion and Analysis of Financial Condition and Results of Operations. These laws and regulations continue to increase in both number and complexity and affect our operations with respect to, among other things:

- Permits required in connection with exploration, drilling, production and other activities.The discharge of pollutants into the environment.
- Emissions into the atmosphere, such as nitrogen oxides, sulfur dioxide, mercury and GHG emissions.
- Carbon taxes.
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardous and nonhazardous wastes.
- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives.
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, oil sands reservoirs and unconventional plays.

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. Any failure by us to comply with existing or future laws, regulations and other requirements could result in administrative or civil penalties, criminal fines, other enforcement actions or third-party litigation against us. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our business, financial condition, results of operations and cash flows in future periods could be materially adversely affected.

Existing and future laws, regulations and initiatives relating to global climate change, such as limitations on GHG emissions, may impact or limit our business plans, result in significant expenditures, promote alternative uses of energy or reduce demand for our products.

Continuing political and social attention to the issue of global climate change has resulted in both existing and pending international agreements and national, regional or local legislation and regulatory measures to limit GHG emissions, such as cap and trade regimes, carbon taxes, restrictive permitting, increased fuel efficiency standards and incentives or mandates for renewable energy. For example, in December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris that prepared an agreement requiring member countries to review and represent a progression in their intended GHG emission reduction goals every five years beginning in 2020. While the U.S. announced its intention to withdraw from the Paris Agreement, there is no guarantee that the commitments made by the U.S. will not be implemented, in whole or in part, by U.S. state and local governments or by major corporations headquartered in the U.S. In addition, our operations continue in countries around the world which are party to, and have not announced an intent to withdraw from, the Paris Agreement. The implementation of current agreements and regulatory measures, as well as any future agreements or measures addressing climate change and GHG emissions, may adversely impact the demand for our products, impose taxes on our products or operations or require us to purchase emission credits or reduce emission of GHGs from our operations. As a result, we may experience declines in commodity prices or incur substantial capital expenditures and compliance, operating, maintenance and remediation costs, any of which may have an adverse effect on our business and results of operations.

Additionally, increasing attention to global climate change has resulted in pressure upon shareholders, financial institutions and/or financial markets to modify their relationships with oil and gas companies and to limit investments and/or funding to such companies, which could increase our costs or otherwise adversely affect our business and results of operations.

Furthermore, increasing attention to global climate change has resulted in an increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely affect our business. In 2017 and 2018, cities, counties, and a state government in California, New York, Washington, Rhode Island and Maryland, as well as the Pacific Coast Federation of Fishermen's Association, Inc., filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. ConocoPhillips is vigorously defending against these lawsuits. The ultimate outcome and impact to us cannot be predicted with certainty, and we could incur substantial legal costs associated with defending these and similar lawsuits in the future.

In addition, although we design and operate our business operations to accommodate expected climatic conditions, to the extent there are significant changes in the earth's climate, such as more severe or frequent weather conditions in the markets where we operate or the areas where our assets reside, we could incur increased expenses, our operations could be adversely impacted, and demand for our products could fall.
For more information on legislation or precursors for possible regulation relating to global climate change that affect or could affect our operations and a description of the company's response, see the "Contingencies—Climate Change" section of Management's Discussion and Analysis of Financial Condition and Results of Operations.

Domestic and worldwide political and economic developments could damage our operations and materially reduce our profitability and cash flows.

Actions of the U.S., state, local and foreign governments, through sanctions, tax and other legislation, executive order and commercial restrictions, could reduce our operating profitability both in the U.S. and abroad. In certain locations, governments have imposed or proposed restrictions on our operations; special taxes or tax assessments; and payment transparency regulations that could require us to disclose competitively sensitive information or might cause us to violate non-disclosure laws of other countries.

One area subject to significant political and regulatory activity is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower permeability rock formations. A range of local, state, federal and national laws and regulations currently govern or, in some hydraulic fracturing operations, prohibit hydraulic fracturing in some jurisdictions. Although hydraulic fracturing has been conducted for many decades, a number of new laws, regulations and permitting requirements are under consideration by the U.S. EPA and others which could result in increased costs, operating restrictions, operational delays or limit the ability to develop oil and natural gas resources. Certain jurisdictions in which we operate, including state and local governments in Colorado, have adopted or are considering 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. In addition, certain interest groups have also proposed ballot initiatives and constitutional amendments designed to restrict oil and natural-gas development generally and hydraulic fracturing in particular. For example, in 2018, Colorado voters rejected Proposition 112, a Colorado ballot initiative that would have drastically limited the use of hydraulic fracturing in Colorado. 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, 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. 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.

The U.S. government can also prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries. Actions by host governments, such as the expropriation of our oil assets by the Venezuelan government, have affected operations significantly in the past and may continue to do so in the future. Changes in domestic and international regulations may affect our ability to collect payments such as those pertaining to the settlement with PDVSA or the ICSID Award against the Government of Venezuela; or to obtain or maintain permits, including those necessary for drilling and development of wells in various locations.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 50 percent of our hydrocarbon production was derived from production outside the U.S. in 2019, and 39 percent of our proved reserves, as of December 31, 2019, were located outside the U.S. We are subject to risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, bitumen, NGLs or LNG pricing and taxation, other political, economic or diplomatic developments (including the effect of international trade discussion and disputes), changing political conditions and international monetary and currency rate fluctuations. In addition, some countries where we operate lack a fully independent judiciary system. This, coupled with changes in foreign law or policy, results in a lack of legal certainty that exposes our operations to increased risks, including increased difficulty in enforcing our agreements in those jurisdictions and increased risks of adverse actions by local government authorities, such as expropriations.

Our business may be adversely affected by price controls, government-imposed limitations on production of crude oil, bitumen, natural gas and NGLs, or the unavailability of adequate gathering, processing, compression, transportation, and pipeline facilities and equipment for our production of crude oil, bitumen, natural gas and NGLs.

As discussed above, our operations are subject to extensive governmental regulations. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil, bitumen, natural gas and NGL wells below actual production capacity. Because legal requirements are frequently changed and subject to interpretation, we cannot predict whether future restrictions on our business may be enacted or become applicable to us.

Our ability to sell and deliver the crude oil, bitumen, natural gas, NGLs and LNG that we produce also depends on the availability, proximity, and capacity of gathering, processing, compression, transportation and pipeline facilities and equipment, as well as any necessary diluents to prepare our crude oil, bitumen, natural gas, NGLs and LNG for transport. The facilities, equipment and diluents we rely on may be temporarily unavailable to us due to market conditions, extreme weather events, regulatory reasons, mechanical reasons or other factors or conditions, many of which are beyond our control. In addition, in certain newer plays, the capacity of necessary facilities, equipment and diluents may not be sufficient to accommodate production from existing and new wells, and construction and permitting delays, permitting costs and regulatory or other constraints could limit or delay the construction, manufacture or other acquisition of new facilities and equipment. If any facilities, equipment or diluents, or any of the transportation methods and channels that we rely on become unavailable for any period of time, we may incur increased costs to transport our crude oil, bitumen, natural gas, NGLs and LNG for sale or we may be forced to curtail our production of crude oil, bitumen, natural gas or NGLs.

Our investments in joint ventures decrease our ability to manage risk.

We conduct many of our operations through joint ventures in which we may share control with our joint venture partners. There is a risk our joint venture participants may at any time have economic, business or legal interests or goals that are inconsistent with those of the joint venture or us, or our joint venture partners may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. Failure by us, or an entity in which we have a joint venture interest, to adequately manage the risks associated with any operations, acquisitions or dispositions could have a material adverse effect on the financial condition or results of operations of our joint ventures and, in turn, our business and operations.

We may not be able to successfully complete any disposition we elect to pursue.

From time to time, we may seek to divest portions of our business or investments that are not important to our ongoing strategic objectives. Any dispositions we undertake may involve numerous risks and uncertainties, any of which could adversely affect our results of operations or financial condition. In particular, we may not be able to successfully complete any disposition on a timeline or on terms acceptable to us, if at all, whether due to market conditions, regulatory challenges or other concerns. In addition, the reinvestment of capital from disposition proceeds may not ultimately yield investment returns in line with our internal or external expectations. Any dispositions we pursue may also result in disruption to other parts of our business, including through the diversion of resources and management attention from our ongoing business and other strategic matters, or through the disruption of relationships with our employees and key vendors. Further, in connection with any disposition, we may enter into transition services agreements or undertake indemnity or other obligations that may result in additional expenses for us. We may also be required under applicable accounting rules to recognize impairments associated with any disposition we pursue, whether or not completed.

As part of our disposition strategy, on May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction included 208 million Cenovus Energy common shares. We may not be able to liquidate the shares issued to us by Cenovus Energy at prices we deem acceptable, or at all.

Our operations present hazards and risks that require significant and continuous oversight.

The scope and nature of our operations present a variety of significant hazards and risks, including operational hazards and risks such as explosions, fires, crude oil spills, severe weather, geological events, labor disputes, armed hostilities, terrorist attacks, sabotage, civil unrest or cyber attacks. Our operations may also be adversely affected by unavailability, interruptions or accidents involving services or infrastructure required to develop, produce, process or transport our production, such as contract labor, drilling rigs, pipelines, railcars, tankers, barges or other infrastructure. Our operations are subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. Offshore activities may pose incrementally greater risks because of complex subsurface conditions such as higher reservoir pressures, water depths and metocean conditions. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations, substantial losses to us and damage to our reputation. Further, our business and operations may be disrupted if we do not respond, or are perceived not to respond, in an appropriate manner to any of these hazards and risks or any other major crisis or if we are unable to efficiently restore or replace affected operational components and capacity.

Our technologies, systems and networks may be subject to cyber attacks.

Our business, like others within the oil and gas industry, has become increasingly dependent on digital technologies, some of which are managed by third-party service providers on whom we rely to help us collect, host or process information. Among other activities, we rely on digital technology to estimate oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information and communicate with employees and third parties. As a result, we face various cyber security threats such as attempts to gain unauthorized access to, or control of, sensitive information about our operations and our employees, attempts to render our data or systems (or those of third parties with whom we do business) corrupted or unusable, threats to the security of our facilities and infrastructure as well as those of third parties with whom we do business and attempted cyber terrorism.

In addition, computers control oil and gas production, processing equipment and distribution systems globally and are necessary to deliver our production to market. A disruption, failure or a cyber breach of these operating systems, or of the networks and infrastructure on which they rely, many of which are not owned or operated by us, could damage critical production, distribution or storage assets, delay or prevent delivery to markets or make it difficult or impossible to accurately account for production and settle transactions.

Although we have experienced occasional breaches of our cyber security, none of these breaches have had a material effect on our business, operations or reputation. As cyber attacks continue to evolve, we must continually expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities detected. 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. Despite our ongoing investments in security resources, talent and business practices, we are unable to assure that any security measures will be effective.

If our systems and infrastructure were to be breached, damaged or disrupted, we could be subject to serious negative consequences, including disruption of our operations, damage to our reputation, a loss of counterparty trust, reimbursement or other costs, increased compliance costs, significant litigation exposure and legal liability or regulatory fines, penalties or intervention. Any of these could materially and adversely affect our business, results of operations or financial condition. Although we have business continuity plans in place, our operations may be adversely affected by significant and widespread disruption to our systems and infrastructure that support our business. While we continue to evolve and modify our business continuity plans, there can be no assurance that they will be effective in avoiding disruption and business impacts. Further, our insurance may not be adequate to compensate us for all resulting losses, and the cost to obtain adequate coverage may increase for us in the future.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 2019, as well as matters previously reported in our 2018 Form 10-K and our first-, second- and third-quarter 2019 Form 10-Qs that were not resolved prior to the fourth quarter of 2019. Material developments to the previously reported matters have been included in the descriptions below. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were to be decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to SEC regulations.

On April 30, 2012, the separation of our downstream business was completed, creating two independent energy companies: ConocoPhillips and Phillips 66. In connection with the separation, we entered into an Indemnification and Release Agreement, which provides for cross-indemnities between Phillips 66 and us and established procedures for handling claims subject to indemnification and related matters, such as legal proceedings. We have included matters where we remain or have subsequently become a party to a proceeding relating to Phillips 66, in accordance with SEC regulations. We do not expect any of those matters to result in a net claim against us.

Matters Previously Reported—Phillips 66
In May 2012, the Illinois Attorney General's office filed and notified ConocoPhillips of a complaint with respect to operations at the Phillips 66 WRB Wood River Refinery alleging violations of the Illinois groundwater standards and a third-party's hazardous waste permit. The complaint seeks remediation of area groundwater; compliance with the hazardous waste permit; enhanced pipeline and tank integrity measures; additional spill reporting; and yet-to-be specified amounts for fines and penalties.

Matters Previously Reported—ConocoPhillips
On June 28, 2018, the Texas Commission on Environmental Quality issued a Proposed Agreed Order to ConocoPhillips Company to resolve alleged violations of the Texas Health & Safety Code and/or Commission Rules occurring in 2015 through 2017 at a formerly owned gas injection plant in Howard County, Texas. In November of 2019, the company concluded this matter by entering into an Agreed Order with the agency and paying an administrative penalty of $120,014.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

Name	Position Held	Age*
Catherine A. Brooks	Vice President and Controller	54
William L. Bullock, Jr.	President, Asia Pacific & Middle East	55
Ellen R. DeSanctis	Senior Vice President, Corporate Relations	63
Matt J. Fox	Executive Vice President and Chief Operating Officer	59
Michael D. Hatfield	President, Alaska, Canada and Europe	53
Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer	57
Andrew D. Lundquist	Senior Vice President, Government Affairs	59
Dominic E. Macklon	President, Lower 48	50
Kelly B. Rose	Senior Vice President, Legal, General Counsel and Corporate Secretary	53
Don E. Wallette, Jr.	Executive Vice President and Chief Financial Officer	61

**On February 15, 2020.*

There are no family relationships among any of the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the company holds office from the date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 12, 2020. Set forth below is information about the executive officers.

Catherine A. Brooks was appointed Vice President and Controller as of January 1, 2019, having previously served as General Auditor since August 2018. Prior to serving as General Auditor, she was Assistant Controller from February 2016 to August 2018. She became Manager, Finance & Performance Analysis in April 2014 and served in that role until February 2016. Ms. Brooks previously held the position of Manager, External Reporting from May 2010 to April 2014.

William L. Bullock, Jr. was appointed President, Asia Pacific & Middle East as of April 1, 2015, having previously served as Vice President, Corporate Planning & Development since May 2012.

Ellen R. DeSanctis was appointed Senior Vice President, Corporate Relations as of January 1, 2019, having previously served as Vice President, Investor Relations and Communications since May 2012. Prior to that, she was employed by Petrohawk Energy Corp. where she served as Senior Vice President, Corporate Communications since 2010.

Matt J. Fox was appointed Executive Vice President and Chief Operating Officer as of January 1, 2019, having previously served as Executive Vice President, Strategy, Exploration and Technology since April 2016 and Executive Vice President, Exploration and Production, from 2012 to 2016. Prior to that, he was employed by Nexen, Inc., where he served as Executive Vice President, International since 2010.

Michael D. Hatfield was appointed President, Alaska, Canada and Europe as of June 3, 2018, having previously served as President, Canada since October 2016. Prior to that, he served as Vice President, Health, Safety and Environment from December 2015 to October 2016. Mr. Hatfield became Vice President, Cost Optimization in March 2015 and served in that role until December 2015. Mr. Hatfield previously held the position of Vice President, Rockies Business Unit from March 2013 to March 2015.

Ryan M. Lance was appointed Chairman of the Board of Directors and Chief Executive Officer in May 2012, having previously served as Senior Vice President, Exploration and Production—International since May 2009.

Andrew D. Lundquist was appointed Senior Vice President, Government Affairs in 2013. Prior to that, he served as managing partner of BlueWater Strategies LLC, since 2002.

Dominic E. Macklon was appointed President, Lower 48 as of June 1, 2018, having previously served as Vice President, Corporate Planning & Development since January 2017. Prior to that, he served as President, U.K. from September 2015 to January 2017. Mr. Macklon previously served as Senior Vice President, Oil Sands from July 2012 to September 2015.

Kelly B. Rose was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary in September 2018. Prior to that, she was a senior partner in the Houston office of an international law firm, Baker Botts L.L.P., where she counseled clients on corporate and securities matters. She began her career at the firm in 1991.

Don E. Wallette, Jr. was appointed Executive Vice President and Chief Financial Officer on January 1, 2019, having previously served as Executive Vice President, Finance, Commercial and Chief Financial Officer since April 2016 and as Executive Vice President, Commercial, Business Development and Corporate Planning from 2012 to 2016. Prior to that, he served as President, Asia Pacific from 2010 to 2012 and President, Russia/Caspian from 2006 to 2010.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

ConocoPhillips' common stock is traded on the New York Stock Exchange, under the symbol "COP."

Cash Dividends Per Share

	Dividends	
	2019	2018
First	$ **0.305**	0.285
Second	**0.305**	0.285
Third	**0.305**	0.285
Fourth	**0.420**	0.305

Number of Stockholders of Record at January 31, 2020*	41,821

**In determining the number of stockholders, we consider clearing agencies and security position listings as one stockholder for each agency listing.*

The declaration of dividends is subject to the discretion of our Board of Directors, and may be affected by various factors, including our future earnings, financial condition, capital requirements, levels of indebtedness, credit ratings and other considerations our Board of Directors deems relevant. Our Board of Directors has adopted a quarterly dividend declaration policy providing that the declaration of any dividends will be determined quarterly by the Board of Directors taking into account such factors as our business model, prevailing business conditions and our financial results and capital requirements, without a predetermined annual net income payout ratio.

On February 1, 2018, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.285 per share, compared with the previous quarterly dividend of $0.265 per share.

On October 5, 2018, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.305 per share, compared with the previous quarterly dividend of $0.285 per share.

On October 7, 2019, we announced that our Board of Directors approved an increase in the quarterly dividend to $0.42 per share, compared with the previous quarterly dividend of $0.305 per share.

Issuer Purchases of Equity Securities

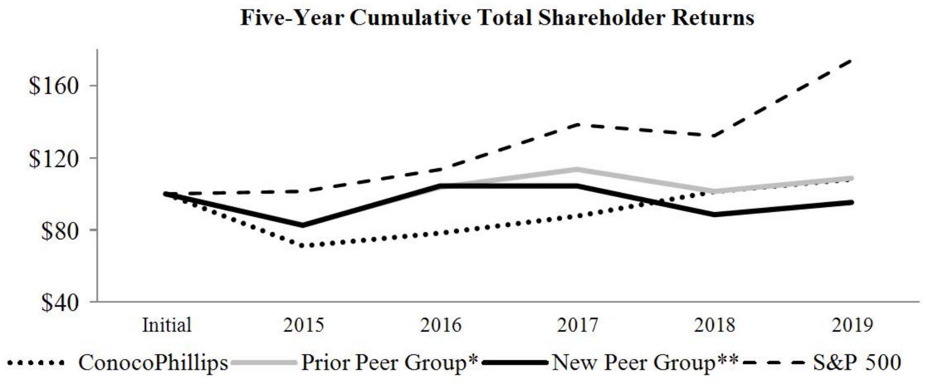
Period	Total Number of Shares Purchased*	Average Price Paid Per Share	Shares Purchased as Part of Publicly Announced Plans or Programs	Millions of Dollars Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 1-31, 2019	4,844,970	$ 55.54	4,844,970	$ 5,855
November 1-30, 2019	4,020,276	58.20	4,020,276	5,621
December 1-31, 2019	3,943,490	62.31	3,943,490	5,375
	12,808,736	$ 58.46	12,808,736	

**There were no repurchases of common stock from company employees in connection with the company's broad-based employee incentive plans.*

In late 2016, we initiated our current share repurchase program. As of December 31, 2019, we had announced a total authorization to repurchase $15 billion of our common stock. We repurchased $3 billion in 2017, $3 billion in 2018 and $3.5 billion in 2019. Of the remaining authorization, we expect to repurchase $3 billion in 2020. In February 2020, we announced that the Board of Directors approved an increase to our repurchase authorization from $15 billion to $25 billion, to support our plan for future share repurchases. Acquisitions for the share repurchase program are made at management's discretion, at prevailing prices, subject to market conditions and other factors. Except as limited by applicable legal requirements, repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan are held as treasury shares. See Risk Factors "Our ability to declare and pay dividends and repurchase shares is subject to certain considerations."

Stock Performance Graph

The following graph shows the cumulative total shareholder return (TSR) for ConocoPhillips' common stock in each of the five years from December 31, 2014, to December 31, 2019. The graph also compares the cumulative total returns for the same five-year period with the S&P 500 Index, the performance peer group used in the prior fiscal year (the "Prior Peer Group") and a new performance peer group for the current fiscal year (the "New Peer Group"). The Prior Peer Group consists of BP, Chevron, ExxonMobil, Royal Dutch Shell, Total, Apache, Devon, Marathon Oil Corporation and Occidental, weighted according to the respective peer's stock market capitalization at the beginning of each annual period. For the purpose of aligning to performance peers with similar complexities and portfolios, the New Peer Group excludes BP, Royal Dutch Shell, and Total, and includes Noble Energy, Hess, and EOG Resources. For the 2018 Stock Performance Graph, Anadarko was also presented within the Prior Peer Group. However, due to Anadarko's acquisition by Occidental completed in 2019, Anadarko's performance has been excluded from all five years of the Prior Peer Group performance. The comparison assumes $100 was invested on December 31, 2014, in ConocoPhillips stock, the S&P 500 Index and ConocoPhillips' peer groups and assumes that all dividends were reinvested. The cumulative total returns of the peer group companies' common stock do not include the cumulative total return of ConocoPhillips' common stock. The stock price performance included in this graph is not necessarily indicative of future stock price performance.



**Prior Peer Group: BP; Chevron; ExxonMobil; Royal Dutch Shell; Total; Apache; Devon, Marathon Oil Corporation; Occidental.*
***New Peer Group: Chevron; ExxonMobil; Apache; Devon; EOG Resources; Hess; Marathon Oil Corporation; Noble Energy; Occidental.*

Item 6. SELECTED FINANCIAL DATA

		Millions of Dollars Except Per Share Amounts				
		2019	2018	2017	2016	2015
Sales and other operating revenues	$	**32,567**	36,417	29,106	23,693	29,564
Net income (loss)		**7,257**	6,305	(793)	(3,559)	(4,371)
Net income (loss) attributable to ConocoPhillips		**7,189**	6,257	(855)	(3,615)	(4,428)
Per common share						
Basic		**6.43**	5.36	(0.70)	(2.91)	(3.58)
Diluted		**6.40**	5.32	(0.70)	(2.91)	(3.58)
Total assets		**70,514**	69,980	73,362	89,772	97,484
Long-term debt		**14,790**	14,856	17,128	26,186	23,453
Cash dividends declared per common share		**1.34**	1.16	1.06	1.00	2.94

In 2019, we disposed of two ConocoPhillips U.K. subsidiaries for proceeds of $2.2 billion after interest and customary adjustments.

In 2017, we disposed of assets for consideration of approximately $16 billion including our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets, and our interests in the San Juan Basin.

These factors impact the comparability of historical information.

See Management’s Discussion and Analysis of Financial Condition and Results of Operations and the Notes to Consolidated Financial Statements for a discussion of factors that will enhance an understanding of this data.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis is the company's analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "anticipate," "estimate," "believe," "budget," "continue," "could," "intend," "may," "plan," "potential," "predict," "seek," "should," "will," "would," "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 70.

The terms "earnings" and "loss" as used in Management's Discussion and Analysis refer to net income (loss) attributable to ConocoPhillips.

BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

ConocoPhillips is an independent E&P company with operations and activities in 17 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; conventional assets in North America, Europe, Asia and Australia; LNG developments; oil sands in Canada; and an inventory of global conventional and unconventional exploration prospects. Headquartered in Houston, Texas, at December 31, 2019, we employed approximately 10,400 people worldwide and had total assets of $71 billion.

Overview

Global oil prices continued to be volatile in 2019. Optimism about worldwide economic growth during the first quarter turned to pessimism in the second quarter as trade disputes dampened growth forecasts. At the end of the second quarter, geopolitical tensions in the Middle East, threatening the safe passage of supertankers carrying crude oil through the Persian Gulf, revived oil prices. Worldwide economic growth concerns returned in the third quarter to depress prices, only to be reversed again by geopolitical tensions in the Middle East, as oilfield infrastructure in Saudi Arabia was attacked, temporarily disrupting approximately five percent of the world's oil supply. Production was restored relatively quickly, and prices settled in the fourth quarter. Brent crude averaged $64 per barrel in 2019, down nine percent from the prior year. Our business strategy anticipates prices will remain volatile and is designed to be resilient in lower price environments, while retaining upside during periods of higher prices. Portfolio diversification and optimization, a strong balance sheet and disciplined capital investment have positioned our company to navigate through volatile energy cycles.

Our value proposition principles, namely, to focus on financial returns, maintain a strong balance sheet, deliver compelling returns of capital, and expand cash flow through disciplined capital investments, are being executed in accordance with our priorities for allocating cash flows from the business. These priorities are: invest capital to sustain production and pay our existing dividend; grow our existing dividend; maintain debt at a level we believe is sufficient to maintain a strong investment grade credit rating through price cycles; allocate greater than 30 percent of our net cash provided by operating activities to share repurchases and dividends; and, invest capital in a disciplined fashion to grow our cash from operations. We believe our commitment to our value proposition, as evidenced by the results discussed below, positions us for success in an environment of price uncertainty and ongoing volatility.

In 2019, we successfully delivered on our priorities. We achieved production growth of five percent on a total BOE basis compared with the prior year, with higher value oil volumes growing eight percent. Cash provided by operating activities of $11.1 billion exceeded capital expenditures and investments of $6.6 billion. After repurchasing $3.5 billion of our common stock and paying $1.5 billion of dividends to shareholders, we ended the year with cash, cash equivalents and restricted cash totaling $5.4 billion and $3.0 billion of short-term investments. In October, we announced an increase to our quarterly dividend of 38 percent to $0.42 per share and announced planned 2020 share buybacks of $3 billion.

In February 2020, we announced 2020 operating plan capital of $6.5 billion to $6.7 billion. The plan includes funding for ongoing development drilling programs, major projects, exploration and appraisal activities, as well as base maintenance. Capital spend is expected to be higher in the first quarter largely from winter construction and exploration and appraisal drilling in Alaska. This guidance does not include capital for acquisitions.

Key Operating and Financial Summary

Significant items during 2019 included the following:

- Net cash provided by operating activities was $11.1 billion and exceeded capital expenditures and investments of $6.6 billion.
- Repurchased $3.5 billion of shares and paid $1.5 billion in dividends, representing 45 percent of net cash provided by operating activities.
- Increased the quarterly dividend by 38 percent to $0.42 per share.
- Achieved 100 percent total reserve replacement and 117 percent organic replacement.
- Underlying production, which excludes Libya and the net volume impact from closed dispositions and acquisitions of 51 MBOED in 2019 and 47 MBOED in 2018, grew 5 percent.
- Increased production from the Lower 48 Big 3 unconventionals—Eagle Ford, Bakken and Permian Unconventional—by 22 percent year-over-year.
- Executed successful Alaska appraisal program; conducted appraisal drilling and commissioned infrastructure at Montney in Canada.
- Completed Lower 48, Alaska and Argentina acquisitions; awarded a 20-year extension of the Indonesia Corridor Block PSC, with new terms.
- Generated $3 billion in disposition proceeds; entered into agreements to sell Australia-West assets for $1.4 billion and Niobrara for $0.4 billion, both subject to customary closing adjustments, as well as regulatory and other approvals.
- Reduced asset retirement obligations and accrued environmental costs by $2.3 billion, primarily due to closed and pending dispositions.
- Ended the year with cash, cash equivalents and restricted cash totaling $5.4 billion and short-term investments of $3.0 billion.
- Recognized a $296 million after-tax impairment related to the sale of our Niobrara interests in the Lower 48 segment.
- Discontinued exploration activities in the Central Louisiana Austin Chalk trend and recognized $197 million after-tax in leasehold impairment and dry hole expenses.

Operationally, we remain focused on safely executing our operating plan and maintaining capital and cost discipline. Production of 1,348 MBOED increased 5 percent or 65 MBOED in 2019 compared with 2018. Production, excluding Libya, of 1,305 MBOED increased 5 percent or 63 MBOED. Underlying production, which excludes Libya and the net volume impact from closed dispositions and acquisitions of 51 MBOED in 2019 and 47 MBOED in 2018, is used to measure our ability to grow production organically. Our underlying production grew 5 percent in 2019 to 1,254 MBOED from 1,195 MBOED in 2018.

On September 30, 2019, we completed the sale of two ConocoPhillips U.K. subsidiaries to Chrysaor E&P Limited for proceeds of $2.2 billion after interest and customary adjustments. In 2019, we recorded a $1.7 billion before-tax and $2.1 billion after-tax gain associated with this transaction. Together the subsidiaries sold our indirectly held exploration and production assets in the U.K., including $1.8 billion of ARO. Annualized average production associated with the U.K. assets sold was 50 MBOED in 2019. Reserves associated with the U.K. assets sold were 84 MMBOE at the time of disposition. Results of operations for the U.K. are reported within our Europe and North Africa segment.

In the second quarter of 2019, we completed the sale of our 30 percent interest in the Greater Sunrise Fields to the government of Timor-Leste for $350 million and recognized an after-tax gain of $52 million. No production or reserve impacts were associated with the sale. The Greater Sunrise Fields were included in our Asia Pacific and Middle East segment.

In October 2019, we entered into an agreement to sell the subsidiaries that hold our Australia-West assets and operations to Santos for $1.39 billion, plus customary adjustments, with an effective date of January 1, 2019. In addition, we will receive a payment of $75 million upon final investment decision of the Barossa development project. These subsidiaries hold our 37.5 percent interest in the Barossa Project and Caldita Field, our 56.9 percent interest in the Darwin LNG Facility and Bayu-Undan Field, our 40 percent interest in the Greater Poseidon Fields, and our 50 percent interest in the Athena Field. This transaction is expected to be completed in the first quarter of 2020, subject to regulatory approvals and the satisfaction of other specific conditions precedent. In 2019, production associated with the Australia-West assets to be sold was 48 MBOED. Year-end 2019 reserves associated with these assets were 17 MMBOE. We will retain our 37.5 percent interest in the Australia Pacific LNG project and operatorship of that project's LNG facility. Results of operations for the subsidiaries to be sold are reported within our Asia Pacific and Middle East segment.

In the fourth quarter of 2019, we signed an agreement to sell our interests in the Niobrara shale play for $380 million, plus customary adjustments, and overriding royalty interests in certain future wells. We recorded an after-tax impairment of $296 million in the fourth quarter of 2019 to reduce the carrying value to fair value. In 2019, production from Niobrara was 11 MBOED. Year-end 2019 reserves associated with the Niobrara assets to be sold were 14 MMBOE. This transaction is subject to regulatory approval and other conditions precedent and is expected to close in the first quarter of 2020. The Niobrara results of operations are reported within our Lower 48 segment.

For more information regarding the accounting impacts of these transactions, see Note 5—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements.

Business Environment

Brent crude oil prices averaged $64 per barrel in 2019, ranging from a low of $53 per barrel in January to a high of almost $75 per barrel in April. The energy industry has periodically experienced this type of volatility due to fluctuating supply-and-demand conditions and such volatility may persist for the foreseeable future. Commodity prices are the most significant factor impacting our profitability and related reinvestment of operating cash flows into our business. Our strategy is to create value through price cycles by delivering on the foundational principles that underpin our value proposition; focus on financial returns through cash flow expansion, maintain balance sheet strength and deliver peer-leading distributions.

Operational and Financial Factors Affecting Profitability
The focus areas we believe will drive our success through the price cycles include:

- Maintain a relentless focus on safety and environmental stewardship. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities, and we are committed to protecting the health and safety of everyone who has a role in our operations and the communities in which we operate. We strive to conduct our business with respect and care for both the local and global environment and systematically manage risk to drive sustainable business growth. Demonstrating our commitment to sustainability and environmental stewardship, on November 2017, we announced our intention to target a 5 to 15 percent reduction in our GHG emission intensity by 2030. In December 2018, we became a founding member of the Climate Leadership Council (CLC), an international policy institute founded in collaboration with business and environmental interests to develop a carbon dividend plan. Participation in the CLC provides another opportunity for ongoing dialogue about carbon pricing and framing the issues in alignment with our public policy principles. We also belong to and fund Americans For Carbon Dividends, the education and advocacy branch of the CLC. In early 2019, we issued our first stand-alone Climate-related Risk Report and incorporated this into our website during our annual Sustainability Report update. Our sustainability efforts continued through 2019 with a focus on advancing our action plans for climate change, biodiversity, water and human rights. We are committed to building a learning organization using human performance principles as we relentlessly pursue improved HSE and operational performance.

- Focus on financial returns. This is a core principle of our value proposition. Our goal is to achieve strong financial returns by exercising capital discipline, controlling our costs, and continually optimizing our portfolio.

  - Maintain capital allocation discipline. We participate in a commodity price-driven and capital-intensive industry, with varying lead times from when an investment decision is made to the time an asset is operational and generates cash flow. As a result, we must invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, and construct pipelines and LNG facilities. We allocate capital across a geographically diverse, low cost of supply resource base, which combined with legacy assets results in low production decline. Cost of supply is the WTI equivalent price that generates a 10 percent after-tax return on a point-forward and fully burdened basis. Fully burdened includes capital infrastructure, foreign exchange, price related inflation and G&A. In setting our capital plans, we exercise a rigorous approach that evaluates projects using this cost of supply criteria, which should lead to value maximization and cash flow expansion using an optimized investment pace, not production growth for growth's sake. Additional capital may be allocated toward growth, but discipline will be maintained. Our cash allocation priorities call for the investment of sufficient capital to sustain production and pay the existing dividend.

    In February 2020, we announced 2020 operating plan capital of $6.5 billion to $6.7 billion. The plan includes funding for ongoing development drilling programs, major projects, exploration and appraisal activities, as well as base maintenance. Capital spend is expected to be higher in the first quarter largely from winter construction and exploration and appraisal drilling in Alaska. This guidance does not include capital for acquisitions.

  - Control costs and expenses. Controlling operating and overhead costs, without compromising safety and environmental stewardship, is a high priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Managing operating and overhead costs is critical to maintaining a competitive position in our industry, particularly in a low commodity price environment. The ability to control our operating and overhead costs impacts our ability to deliver strong cash from operations. In 2019, our production and operating expenses were two percent higher than 2018, primarily due to costs associated with higher production volumes, which grew five percent during the same period.

  - Optimize our portfolio. We continue to optimize our asset portfolio to focus on low cost of supply assets that support our strategy. In 2019, we continued to dispose of or market certain non-core assets, including the U.K., Australia-West and our Niobrara assets in the Lower 48. Additions to the portfolio were made in the Lower 48 with bolt-on interests and acreage acquisitions, in Alaska with the Nuna discovery acreage acquisition, and internationally with entrance into Argentina's Neuquén and Austral Basins. We will continue to evaluate our assets to determine whether they compete for capital within our portfolio and will optimize the portfolio as necessary, directing capital towards the most competitive investments.

- Maintain balance sheet strength. We believe balance sheet strength is critical in a cyclical business such as ours. Our strong operating performance buffered by a solid balance sheet enables us to deliver on our priorities through the price cycles. Our priorities include execution of our development plans, maintaining a growing dividend, and repurchasing shares on a dollar cost average basis.

- Return value to shareholders. We believe in delivering value to our shareholders via a growing, sustainable dividend supplemented by share repurchases. In 2019, we paid dividends on our common stock of approximately $1.5 billion and repurchased $3.5 billion of our common stock. Combined, our dividend and repurchases represented 45 percent of our net cash provided by operating activities. Since we initiated our current share repurchase program in late 2016, we have repurchased $9.6 billion of shares. Additionally, as of December 31, 2019, $5.4 billion of repurchase authority remained of the $15 billion share repurchase program our Board of Directors had authorized. In February 2020, we announced that the Board of Directors approved an increase to our repurchase authorization from $15 billion to $25 billion, to support our plan for future share repurchases. Whether we undertake these additional repurchases is ultimately subject to numerous considerations, including market conditions and other factors. See Risk Factors "Our ability to declare and pay dividends and repurchase shares is subject to certain considerations."

  In October 2019, we announced that our Board of Directors approved an increase to our quarterly dividend of 38 percent to $0.42 per share.

- Add to our proved reserve base. We primarily add to our proved reserve base in three ways:

  - Successful exploration, exploitation and development of new and existing fields.
  - Application of new technologies and processes to improve recovery from existing fields.
  - Purchases of increased interests in existing fields and bolt-on acquisitions.

  Proved reserve estimates require economic production based on historical 12-month, first-of-month, average prices and current costs. Therefore, our proved reserves generally increase as prices rise and decrease as prices decline. Reserve replacement represents the net change in proved reserves, net of production, divided by our current year production, as shown in our supplemental reserve table disclosures. In 2019, our reserve replacement, which included a net decrease of 0.1 billion BOE from sales and purchases, was 100 percent. Increased crude oil reserves accounted for approximately 55 percent of the total change in reserves. Our organic reserve replacement, which excludes the impact of sales and purchases, was 117 percent in 2019. Approximately 50 percent of organic reserve additions were from Lower 48 unconventional assets. The remaining additions were evenly distributed across the other operating segments.

  In the five years ended December 31, 2019, our reserve replacement was negative 34 percent, reflecting the impact of asset dispositions and lower prices during that period. Our organic reserve replacement during the five years ended December 31, 2019, which excludes a decrease of 2.0 billion BOE related to sales and purchases, was 40 percent, reflecting development activities as well as lower prices during that period.

  Historically, our reserve replacement has varied considerably year to year contingent upon the timing of major projects which may have long lead times between capital investment and production. In the last several years, more of our capital has been allocated to short cycle time, onshore, unconventional plays. Accordingly, we believe our recent success in replacing reserves can be viewed on a trailing three-year basis.

  In the three years ended December 31, 2019, our reserve replacement was 23 percent, reflecting the impact of asset dispositions during that period. Our organic reserve replacement during the three years ended December 31, 2019, which excludes a decrease of 1.8 billion BOE related to sales and purchases, was 143 percent, reflecting reserve additions from development activities.

Access to additional resources may become increasingly difficult as commodity prices can make projects uneconomic or unattractive. In addition, prohibition of direct investment in some nations, national fiscal terms, political instability, competition from national oil companies, and lack of access to high-potential areas due to environmental or other regulation may negatively impact our ability to increase our reserve base. As such, the timing and level at which we add to our reserve base may, or may not, allow us to replace our production over subsequent years.

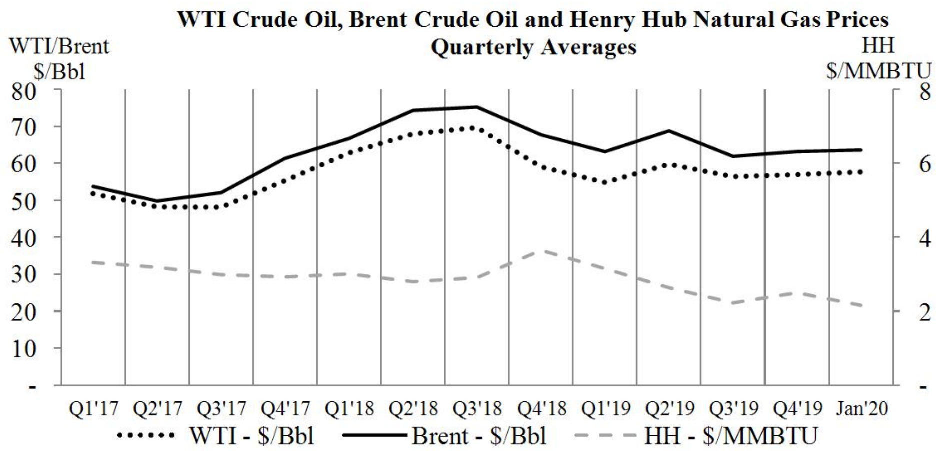
- Apply technical capability. We leverage our knowledge and technology to create value and safely deliver on our plans. Technical strength is part of our heritage and allows us to economically convert additional resources to reserves, achieve greater operating efficiencies and reduce our environmental impact. Companywide, we continue to evaluate potential solutions to leverage knowledge of technological successes across our operations.

  We have embraced the digital transformation and are using digital innovations to work and operate more efficiently. Predictive analytics have been adopted in our operations and planning process. Artificial intelligence, machine learning and deep learning are being used for seismic advancements.

- Attract, develop and retain a talented work force. We strive to attract, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. We offer university internships across multiple disciplines to attract the best early career talent. We also recruit experienced hires to fill critical skills and maintain a broad range of expertise and experience. We promote continued learning, development and technical training through structured development programs designed to enhance the technical and functional skills of our employees.

Other Factors Affecting Profitability
Other significant factors that can affect our profitability include:

- Energy commodity prices. Our earnings and operating cash flows generally correlate with industry price levels for crude oil and natural gas. Industry price levels are subject to factors external to the company and over which we have no control, including but not limited to global economic health, supply disruptions or fears thereof caused by civil unrest or military conflicts, actions taken by OPEC, environmental laws, tax regulations, governmental policies and weather-related disruptions. The following graph depicts the average benchmark prices for WTI crude oil, Brent crude oil and U.S. Henry Hub natural gas:



Brent crude oil prices averaged $64.30 per barrel in 2019, a decrease of 9 percent compared with $71.04 per barrel in 2018. Similarly, WTI crude oil prices decreased 12 percent from $64.92 per barrel in 2018 to $57.02 per barrel in 2019. Crude oil prices weakened year over year primarily due to ample global supplies and a decelerating global economy.

Henry Hub natural gas price averages decreased 15 percent from $3.09 per MMBTU in 2018 to $2.63 per MMBTU in 2019. Natural gas prices weakened in 2019 versus the prior year due to strong production, while demand growth was dampened by mild weather.

Our realized NGL prices decreased 34 percent from $30.48 per barrel in 2018 to $20.09 per barrel in 2019. NGL prices weakened year over year due to strong supply growth with only moderate demand growth.

Our realized bitumen price increased 42 percent from $22.29 per barrel in 2018 to $31.72 per barrel in 2019. Curtailment orders imposed by the Alberta Government, which limited production from the province starting January 2019, provided strength to the WCS differential to WTI at Hardisty. We continue to optimize bitumen price realizations through the utilization of downstream transportation solutions and implementation of alternate blend capability which results in lower diluent costs.

Our worldwide annual average realized price decreased 9 percent from $53.88 per BOE in 2018 to $48.78 per BOE in 2019 due to lower realized oil, natural gas and NGL prices.

North America's energy supply landscape has been transformed from one of resource scarcity to one of abundance. In recent years, the use of hydraulic fracturing and horizontal drilling in unconventional formations has led to increased industry actual and forecasted crude oil and natural gas production in the U.S. Although providing significant short- and long-term growth opportunities for our company, the increased abundance of crude oil and natural gas due to development of unconventional plays could also have adverse financial implications to us, including: an extended period of low commodity prices; production curtailments; and delay of plans to develop areas such as unconventional fields. Should one or more of these events occur, our revenues would be reduced, and additional asset impairments might be possible.

- Impairments. We participate in a capital-intensive industry. At times, our PP&E and investments become impaired when, for example, commodity prices decline significantly for long periods of time, our reserve estimates are revised downward, or a decision to dispose of an asset leads to a write-down to its fair value. We may also invest large amounts of money in exploration which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. As we optimize our assets in the future, it is reasonably possible we may incur future losses upon sale or impairment charges to long-lived assets used in operations, investments in nonconsolidated entities accounted for under the equity method, and unproved properties. A sustained decline in the current and long-term outlook on gas price could affect the carrying value of certain Lower 48 non-core gas assets and it is reasonably possible this could result in a future non-cash impairment. For additional information on our impairments in 2019, 2018 and 2017, see Note 9—Impairments, in the Notes to Consolidated Financial Statements.

- Effective tax rate. Our operations are in countries with different tax rates and fiscal structures. Accordingly, even in a stable commodity price and fiscal/regulatory environment, our overall effective tax rate can vary significantly between periods based on the "mix" of before-tax earnings within our global operations.

- Fiscal and regulatory environment. Our operations can be affected by changing economic, regulatory and political environments in the various countries in which we operate, including the U.S. Civil unrest or strained relationships with governments may impact our operations or investments. These changing environments could negatively impact our results of operations, and further changes to increase government fiscal take could have a negative impact on future operations. Our management carefully considers the fiscal and regulatory environment when evaluating projects or determining the levels and locations of our activity.

Outlook

Full-year 2020 production is expected to be 1,230 MBOED to 1,270 MBOED, including the impact of a recent third-party pipeline outage on the Kebabangan Field in Malaysia. First-quarter 2020 production is expected to be 1,240 MBOED to 1,280 MBOED. Production guidance for 2020 excludes Libya.

Operating Segments

We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, premiums incurred on the early retirement of debt, corporate overhead, certain technology activities, as well as licensing revenues.

Our key performance indicators, shown in the statistical tables provided at the beginning of the operating segment sections that follow, reflect results from our operations, including commodity prices and production.

RESULTS OF OPERATIONS

This section of the Form 10-K discusses year-to-year comparisons between 2019 and 2018. For discussion of year-to-year comparisons between 2018 and 2017, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of our 2018 10-K.

Consolidated Results

A summary of the company's net income (loss) attributable to ConocoPhillips by business segment follows:

		Millions of Dollars		
Years Ended December 31		**2019**	2018	2017
Alaska	$	**1,520**	1,814	1,466
Lower 48		**436**	1,747	(2,371)
Canada		**279**	63	2,564
Europe and North Africa		**2,724**	1,866	553
Asia Pacific and Middle East		**1,929**	2,070	(1,098)
Other International		**263**	364	167
Corporate and Other		**38**	(1,667)	(2,136)
Net income (loss) attributable to ConocoPhillips	$	**7,189**	6,257	(855)

2019 vs. 2018

Net income attributable to ConocoPhillips increased $932 million in 2019. The increase was mainly due to:

- A $2.1 billion after-tax gain associated with the completion of the sale of two ConocoPhillips U.K. subsidiaries to Chrysaor E&P Limited.
- An unrealized gain of $649 million after-tax on our Cenovus Energy (CVE) common shares in 2019, as compared to a $436 million after-tax unrealized loss on those shares in 2018.
- Higher crude oil sales volumes due to growth in the Lower 48 unconventionals and from the acquisition of incremental interests in operated assets in Alaska during the second and fourth quarters of 2018.
- The absence of premiums on early debt retirements totaling $195 million after-tax.
- A $164 million income tax benefit related to deepwater incentive tax credits recognized for Malaysia Block G.
- A $151 million income tax benefit related to the revaluation of deferred tax assets following finalization of rules relating to the 2017 Tax Cuts and Jobs Act.

These increases in net income were partly offset by:

- Lower realized crude oil, natural gas and NGL prices.
- The absence of a $774 million after-tax gain on the Clair disposition in the U.K.
- A $296 million after-tax impairment related to the sale of our Lower 48 Niobrara interests.
- Lower equity in earnings of affiliates due to $120 million of impairments to equity method investments in our Lower 48 segment and a $118 million reduction in equity earnings at QG3 in our Asia Pacific and Middle East segment due to a deferred tax adjustment.
- Higher exploration expenses, primarily in our Lower 48 segment due to $197 million after-tax of leasehold impairment and dry hole costs associated with our decision to discontinue exploration activities in the Central Louisiana Austin Chalk trend.

Income Statement Analysis

2019 vs. 2018

Sales and other operating revenues decreased 11 percent in 2019, mainly due to lower realized crude oil, natural gas and NGL prices, partly offset by higher sales volumes of crude oil in the Lower 48 and Alaska.

Equity in earnings of affiliates decreased $295 million in 2019, primarily due to impairments of equity method investments in our Lower 48 segment totaling $155 million. Additionally, equity earnings decreased $118 million resultant from a deferred tax adjustment at QG3, reported in our Asia Pacific and Middle East segment. For more information related to these items, see Note 3—Variable Interest Entities and Note 5—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements.

Gain on dispositions increased $903 million in 2019, primarily due to a $1.7 billion before-tax gain associated with the completion of the sale of two ConocoPhillips U.K. subsidiaries to Chrysaor E&P Limited. Partly offsetting this increase, was the absence of a $715 million before-tax gain on the sale of a ConocoPhillips subsidiary to BP in 2018, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the U.K. For additional information related to these dispositions, see Note 5—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements.

Other income increased $1,185 million in 2019, primarily due to an unrealized gain of $649 million before-tax on our CVE common shares in 2019, and the absence of a $437 million before-tax unrealized loss on those shares in 2018. For discussion of our CVE shares, see Note 7—Investment in Cenovus Energy, in the Notes to Consolidated Financial Statements.

Purchased commodities decreased 17 percent in 2019, primarily due to lower natural gas and crude oil prices.

Selling, general and administrative expenses increased $155 million in 2019, primarily due to higher costs associated with compensation and benefits, including mark to market impacts of certain key employee compensation programs, and increased facility costs.

Exploration expenses increased $374 million in 2019, primarily due to higher leasehold impairment and dry hole costs, mainly in our Lower 48 segment, and higher exploration G&A expenses. In 2019, we recorded a $141 million before-tax leasehold impairment expense due to our decision to discontinue exploration activities in the Central Louisiana Austin Chalk trend and expensed $111 million of dry hole costs related to this play.

Impairments increased $378 million in 2019, mainly due to a $379 million before-tax impairment related to the sale of our Niobrara interests in the Lower 48 segment. For additional information, see Note 5—Asset Acquisitions and Dispositions and Note 9—Impairments, in the Notes to Consolidated Financial Statements.

Other expenses decreased $310 million in 2019, primarily due to the absence of a $206 million before-tax expense for premiums on early debt retirements and lower pension settlement expense.

See Note 19—Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax provision (benefit) and effective tax rate.

Summary Operating Statistics

		2019	2018	2017
Average Net Production				
Crude oil (MBD)		**705**	653	599
Natural gas liquids (MBD)		**115**	102	111
Bitumen (MBD)		**60**	66	122
Natural gas (MMCFD)		**2,805**	2,774	3,270
Total Production (MBOED)		**1,348**	1,283	1,377
		Dollars Per Unit		
Average Sales Prices				
Crude oil (per bbl)	$	**60.99**	68.13	51.96
Natural gas liquids (per bbl)		**20.09**	30.48	25.22
Bitumen (per bbl)		**31.72**	22.29	22.66
Natural gas (per mcf)		**5.03**	5.65	4.07
		Millions of Dollars		
Worldwide Exploration Expenses				
General and administrative; geological and geophysical, lease rental, and other	$	**322**	274	368
Leasehold impairment		**221**	56	136
Dry holes		**200**	39	430
	$	**743**	369	934

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a worldwide basis. At December 31, 2019, our operations were producing in the U.S., Norway, Canada, Australia, Timor-Leste, Indonesia, China, Malaysia, Qatar and Libya.

2019 vs. 2018

Total production, including Libya, of 1,348 MBOED increased 65 MBOED or 5 percent in 2019 compared with 2018, primarily due to:

- New wells online in the Lower 48.
- An increased interest in the Western North Slope (WNS) and Greater Kuparuk Area (GKA) of Alaska following acquisitions closed in 2018.
- Higher production in Norway due to drilling activity and the startup of Aasta Hansteen in December 2018.

The increase in production during 2019 was partly offset by:

- Normal field decline.
- Disposition impacts from the U.K. and non-core asset sales in the Lower 48.

Production excluding Libya was 1,305 MBOED in 2019 compared with 1,242 MBOED in 2018, an increase of 63 MBOED or 5 percent. Underlying production, which excludes Libya and the net volume impact from closed dispositions and acquisitions of 51 MBOED in 2019 and 47 MBOED in 2018, is used to measure our ability to grow production organically. Our underlying production grew 5 percent to 1,254 MBOED in 2019 from 1,195 MBOED in 2018.

Alaska

		2019	2018	2017
Net Income Attributable to ConocoPhillips (millions of dollars)	$	**1,520**	1,814	1,466
Average Net Production				
Crude oil (MBD)		**202**	171	167
Natural gas liquids (MBD)		**15**	14	14
Natural gas (MMCFD)		**7**	6	7
Total Production (MBOED)		**218**	186	182
Average Sales Prices				
Crude oil (per bbl)	$	**64.12**	70.86	53.33
Natural gas (per mcf)		**3.19**	2.48	2.72

The Alaska segment primarily explores for, produces, transports and markets crude oil, NGLs and natural gas. In 2019, Alaska contributed 25 percent of our worldwide liquids production and less than 1 percent of our natural gas production.

2019 vs. 2018

Alaska reported earnings of $1,520 million in 2019, compared with earnings of $1,814 million in 2018. The decrease in earnings was mainly due to lower realized crude oil prices and higher production and operating and DD&A expenses associated with incremental volumes from acquisitions completed during 2018. Additionally, earnings were lower due to the absence of a $98 million tax valuation allowance reduction, the absence of a $79 million after-tax benefit resulting from an accrual reduction due to a transportation cost ruling by the FERC, and $62 million less in enhanced oil recovery credits. Partly offsetting these decreases in earnings, were higher crude oil sales volumes due to the GKA and WNS acquisitions completed in 2018.

Average production increased 32 MBOED in 2019 compared with 2018, primarily due to acquisitions at GKA and WNS in 2018, which provided an incremental 38 MBOED of production in 2019, as well as volumes from new wells online. These production increases were partly offset by normal field decline.

Acquisition Update
In the third quarter of 2019, we completed the Nuna discovery acreage acquisition for approximately $100 million, expanding the Kuparuk River Unit by 21,000 acres and leveraging legacy infrastructure.

Lower 48

		2019	2018	2017
Net Income (Loss) Attributable to ConocoPhillips				
(millions of dollars)	$	**436**	1,747	(2,371)
Average Net Production				
Crude oil (MBD)		**266**	229	180
Natural gas liquids (MBD)		**81**	69	69
Natural gas (MMCFD)		**622**	596	898
Total Production (MBOED)		**451**	397	399
Average Sales Prices				
Crude oil (per bbl)	$	**55.30**	62.99	47.36
Natural gas liquids (per bbl)		**16.83**	27.30	22.20
Natural gas (per mcf)		**2.12**	2.82	2.73

The Lower 48 segment consists of operations located in the contiguous U.S. and the Gulf of Mexico. During 2019, the Lower 48 contributed 39 percent of our worldwide liquids production and 22 percent of our natural gas production.

2019 vs. 2018

Lower 48 reported earnings of $436 million in 2019, compared with $1,747 million in 2018. Earnings decreased primarily due to lower realized crude oil, NGL and natural gas prices; higher DD&A due to increased production volumes; a $301 million after-tax impairment of our Niobrara assets; higher exploration expenses, primarily due to a combined $197 million after-tax of leasehold impairment and dry hole costs associated with our decision to discontinue exploration activities in the Central Louisiana Austin Chalk; and lower earnings in equity affiliates due to a combined $120 million after-tax of impairments associated with a fair value reduction of our investment in MWCC and the disposition of our interests in the Golden Pass LNG Terminal and Golden Pass Pipeline. Partly offsetting the decrease in earnings were increased crude oil and NGL sales volumes in the Eagle Ford, Bakken and Permian Unconventional.

For additional information related to our impairment of MWCC, see Note 3—Variable Interest Entities in the Notes to Consolidated Financial Statements. For more information related to the sale of our interests in Golden Pass LNG Terminal and Golden Pass Pipeline, see Note 5—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.

Total average production increased 54 MBOED in 2019 compared with 2018. The increase was primarily due to new production from unconventional assets in Eagle Ford, Bakken and the Permian Basin, partly offset by normal field decline. Additionally, production decreased by 10 MBOED due to non-core dispositions in 2018.

Asset Dispositions Update

In January 2019, we entered into agreements to sell our 12.4 percent ownership interests in the Golden Pass LNG Terminal and Golden Pass Pipeline. We have also entered into agreements to amend our contractual obligations for retaining use of the facilities. As a result of entering into these agreements, we recognized a before-tax impairment of $60 million in the first quarter of 2019 which is included in the “Equity in earnings of affiliates” line on our consolidated income statement. We completed the sale in the second quarter of 2019. See Note 15—Fair Value Measurement in the Notes to Consolidated Financial Statements, for additional information.

In the fourth quarter of 2019, we sold our interests in the Magnolia field and platform and recognized an after-tax gain of $63 million. Production from Magnolia in 2019 was less than one MBOED.

In the fourth quarter of 2019, we signed an agreement to sell our interests in the Niobrara shale play for $380 million, plus customary adjustments, and overriding royalty interests in certain future wells. We recorded an after-tax impairment of $301 million in the fourth quarter to reduce the carrying value to fair value. Production from Niobrara was approximately 11 MBOED in 2019. This transaction is subject to regulatory approval and other conditions precedent and is expected to close in the first quarter of 2020.

In January 2020, we entered into an agreement to sell our interests in certain non-core properties in the Lower 48 segment for $186 million, plus customary adjustments. The assets met the held for sale criteria in January 2020 and the transaction is expected to be completed in the first quarter of 2020. No gain or loss is anticipated on the sale. This disposition will not have a significant impact on Lower 48 production.

For additional information on these transactions, see Note 5—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements.

Canada

		2019	2018	2017
Net Income Attributable to ConocoPhillips				
(millions of dollars)	**$**	**279**	63	2,564
Average Net Production				
Crude oil (MBD)		**1**	1	3
Natural gas liquids (MBD)		**-**	1	9
Bitumen (MBD)				
Consolidated operations		**60**	66	59
Equity affiliates		**-**	-	63
Total bitumen		**60**	66	122
Natural gas (MMCFD)		**9**	12	187
Total Production (MBOED)		**63**	70	165
Average Sales Prices				
Crude oil (per bbl)	**$**	**40.87**	48.73	43.69
Natural gas liquids (per bbl)		**19.87**	43.70	21.51
Bitumen (dollars per bbl)*				
Consolidated operations		**31.72**	22.29	21.43
Equity affiliates		**-**	-	23.83
Total bitumen		**31.72**	22.29	22.66
Natural gas (per mcf)		**0.49**	1.00	1.93

**Average prices for sales of bitumen produced during 2018 and 2019 excludes additional value realized from the purchase and sale of third-party volumes for optimization of our pipeline capacity between Canada and the U.S. Gulf Coast.*

Our Canadian operations consist of the Surmont oil sands development in Alberta and the liquids-rich Montney unconventional play in British Columbia. In 2019, Canada contributed 7 percent of our worldwide liquids production and less than one percent of our worldwide natural gas production.

2019 vs. 2018

Canada operations reported earnings of $279 million in 2019 compared with $63 million in 2018. Earnings increased mainly due to higher realized bitumen prices, a $68 million tax benefit primarily comprised of a previously unrecognizable tax basis related to a tax settlement, lower DD&A expense due to lower rates from reserve additions, lower production and operating expenses, and a $25 million tax benefit due to a four year phased four percent reduction in Alberta's corporate income tax rate. Partly offsetting the increase in earnings were lower sales volumes due to a planned turnaround at Surmont, lower production due to a mandated production curtailment imposed by the Alberta government in January 2019, and the absence of an $80 million tax restructuring benefit.

Total average production decreased 7 MBOED in 2019 compared with 2018. The production decrease was primarily due to a turnaround at Surmont, which had an annualized average impact of 3 MBOED, and a mandated production curtailment imposed by the Alberta government, which also impacted production by 3 MBOED. The curtailment program is established and administered by the Alberta Energy Regulator under the Curtailment Rules regulation, which is currently set to expire on December 31, 2020. This program is intended to strengthen the WCS differential to WTI at Hardisty.

Asset Disposition
On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction was $11.0 billion in cash after customary adjustments, 208 million Cenovus Energy common shares and a five year uncapped contingent payment. The contingent payment, calculated and paid on a quarterly basis, is $6 million CAD for every $1 CAD by which the WCS quarterly average crude price exceeds $52 CAD per barrel. During 2019 and 2018, we recorded after-tax gains on dispositions for these contingent payments of $84 million and $68 million, respectively. See Note 5—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements, for additional information.

Europe and North Africa

		2019	2018	2017
Net Income Attributable to ConocoPhillips				
(millions of dollars)	$	**2,724**	1,866	553
Average Net Production				
Crude oil (MBD)		**138**	149	142
Natural gas liquids (MBD)		**7**	8	8
Natural gas (MMCFD)		**478**	503	484
Total Production (MBOED)		**224**	241	230
Average Sales Prices				
Crude oil (dollars per bbl)	$	**64.94**	70.71	54.21
Natural gas liquids (per bbl)		**29.37**	36.87	34.07
Natural gas (per mcf)		**4.92**	7.65	5.70

The Europe and North Africa segment consisted of operations principally located in the Norwegian and U.K. sectors of the North Sea, the Norwegian Sea and Libya. In 2019, our Europe and North Africa operations contributed 16 percent of our worldwide liquids production and 17 percent of our natural gas production.

2019 vs. 2018

Earnings for Europe and North Africa operations of $2,724 million increased $858 million in 2019 compared with 2018. The increase in earnings was primarily due to a $2.1 billion after-tax gain associated with the completion of the sale of two ConocoPhillips U.K. subsidiaries to Chrysaor E&P Limited. Earnings also increased due to the cessation of DD&A in the second quarter of 2019 for our disposed U.K. subsidiaries when these assets became held-for-sale. Partly offsetting the increase in earnings were the absence of a $774 million after-tax gain related to the sale of a ConocoPhillips subsidiary to BP, which held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the U.K.; lower sales volumes primarily due to the U.K. disposition to Chrysaor completed September 30, 2019; and lower realized natural gas and crude oil prices.

Average production decreased 17 MBOED in 2019, compared with 2018. The decrease was mainly due to normal field decline and a 20 MBOED disposition impact from the sale of our U.K. assets to Chrysaor completed September 30, 2019. Partly offsetting these production decreases were volumes from new wells online in Norway, including the Aasta Hansteen Field which achieved first production in December of 2018.

Asset Disposition Update

On September 30, 2019, we completed the sale of two ConocoPhillips U.K. subsidiaries to Chrysaor E&P Limited for proceeds of $2.2 billion after interest and customary adjustments. In 2019, we recorded a $1.7 billion before-tax and $2.1 billion after-tax gain associated with this transaction. Together the subsidiaries sold indirectly held our exploration and production assets in the U.K., including $1.8 billion of ARO. Annualized average production associated with the U.K. assets sold was 50 MBOED in 2019. Reserves associated with the U.K. assets sold were 84 MMBOE at the time of disposition. For additional information, see Note 5—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.

Asia Pacific and Middle East

		2019	2018	2017
Net Income (Loss) Attributable to ConocoPhillips				
(millions of dollars)	$	**1,929**	2,070	(1,098)
Average Net Production				
Crude oil (MBD)				
Consolidated operations		**85**	89	93
Equity affiliates		**13**	14	14
Total crude oil		**98**	103	107
Natural gas liquids (MBD)				
Consolidated operations		**4**	3	4
Equity affiliates		**8**	7	7
Total natural gas liquids		**12**	10	11
Natural gas (MMCFD)				
Consolidated operations		**637**	626	687
Equity affiliates		**1,052**	1,031	1,007
Total natural gas		**1,689**	1,657	1,694
Total Production (MBOED)		**392**	389	401
Average Sales Prices				
Crude oil (dollars per bbl)				
Consolidated operations	$	**65.02**	70.93	54.38
Equity affiliates		**61.32**	72.49	54.76
Total crude oil		**64.52**	71.14	54.43
Natural gas liquids (dollars per bbl)				
Consolidated operations		**37.85**	47.20	41.37
Equity affiliates		**36.70**	45.69	38.74
Total natural gas liquids		**37.10**	46.13	39.75
Natural gas (dollars per mcf)				
Consolidated operations		**5.91**	6.15	4.98
Equity affiliates		**6.29**	6.06	4.27
Total natural gas		**6.15**	6.09	4.55

The Asia Pacific and Middle East segment has operations in China, Indonesia, Malaysia, Australia, Timor-Leste and Qatar. During 2019, Asia Pacific and Middle East contributed 13 percent of our worldwide liquids production and 60 percent of our natural gas production.

2019 vs. 2018

Asia Pacific and Middle East reported earnings of $1,929 million in 2019, compared with $2,070 million in 2018. The decrease in earnings was mainly due to lower realized crude oil, NGL and natural gas prices; lower LNG and crude oil sales volumes; and lower equity in earnings of affiliates, primarily due to a deferred tax adjustment at QG3 that resulted in a $118 million reduction to equity earnings. Partly offsetting this decrease in earnings was a $164 million income tax benefit related to deepwater incentive tax credits from the Malaysia Block G and a $52 million after-tax gain on disposition of our interest in the Greater Sunrise Fields.

Average production increased 1 percent in 2019, compared with 2018. The increase was primarily due to new production from Malaysia, including first gas supply from KBB to PFLNG1 in the second quarter of 2019 and first oil from Gumusut Phase 2 in the third quarter of 2019; and new wells online in China, including Bohai Phase 3. Partly offsetting this production increase was normal field decline.

Asset Dispositions Update
In the second quarter of 2019, we recognized an after-tax gain of $52 million upon completion of the sale of our 30 percent interest in the Greater Sunrise Fields to the government of Timor-Leste for $350 million. No production or reserve impacts were associated with the sale.

In October 2019, we entered into an agreement to sell the subsidiaries that hold our Australia-West assets and operations to Santos for $1.39 billion, plus customary adjustments, with an effective date of January 1, 2019. In addition, we will receive a payment of $75 million upon final investment decision of the Barossa development project. These subsidiaries hold our 37.5 percent interest in the Barossa Project and Caldita Field, our 56.9 percent interest in the Darwin LNG Facility and Bayu-Undan Field, our 40 percent interest in the Greater Poseidon Fields, and our 50 percent interest in the Athena Field. This transaction is expected to be completed in the first quarter of 2020, subject to regulatory approvals and the satisfaction of other specific conditions precedent. In 2019, production associated with the Australia-West assets to be sold was 48 MBOED. Year-end 2019 reserves associated with these assets were 17 MMBOE. We will retain our 37.5 percent interest in the Australia Pacific LNG project and operatorship of that project's LNG facility.

See Note 5—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements, for additional information related to these dispositions.

Other International

		2019	2018	2017
Net Income Attributable to ConocoPhillips (millions of dollars)	$	**263**	364	167

The Other International segment includes exploration activities in Colombia, Chile and Argentina and contingencies associated with prior operations.

2019 vs. 2018

Other International operations reported earnings of $263 million in 2019, compared with earnings of $364 million in 2018. The decrease in earnings was primarily due to the recognition of $417 million after-tax in other income related to a settlement agreement with PDVSA in 2018, compared with $317 million after-tax associated with this settlement agreement in 2019.

In 2018 and 2019, we collected approximately $0.8 billion of the $2.0 billion settlement with PDVSA. PDVSA has defaulted on its remaining payment obligations under this agreement, we are therefore now forced to incur additional costs as we seek to recover any unpaid amounts under the agreement. For additional information, see Note 13—Contingencies and Commitments in the Notes to Consolidated Financial Statements.

Argentina
In January 2019, we secured a 50 percent nonoperated interest in the El Turbio Este Block, within the Austral Basin in southern Argentina. In 2019, we acquired and processed 3-D seismic covering 500 square miles, with evaluation of the data ongoing.

In November 2019, we acquired interests in two nonoperated blocks in the Neuquén Basin targeting the Vaca Muerta play. We have a 50 percent interest in the Bandurria Norte Block and a 45 percent interest in the Aguada Federal Block. In Bandurria Norte, 1 vertical and 4 horizontal wells were tested and shut-in during 2019. In Aguada Federal, 2 horizontal wells were being tested at the end of the year.

Corporate and Other

		Millions of Dollars	
	2019	2018	2017
Net Income (Loss) Attributable to ConocoPhillips			
Net interest	$ **(604)**	(680)	(739)
Corporate general and administrative expenses	**(252)**	(91)	(193)
Technology	**123**	109	20
Other	**771**	(1,005)	(1,224)
	$ **38**	(1,667)	(2,136)

2019 vs. 2018

Net interest consists of interest and financing expense, net of interest income and capitalized interest. Net interest decreased $76 million in 2019 compared with 2018, primarily due to lower capitalized interest on projects; increased interest income from holding higher cash balances; and lower interest on debt expense resultant from the retirement of $4.7 billion of debt in 2018; partly offset by the absence of an accrual reduction due to a transportation cost ruling by the FERC.

Corporate G&A expenses include compensation programs and staff costs. These costs increased by $161 million in 2019 compared with 2018, primarily due to higher costs associated with compensation and benefits, including certain key employee compensation programs and higher facility costs.

Technology includes our investment in new technologies or businesses, as well as licensing revenues. Activities are focused on both conventional and tight oil reservoirs, shale gas, heavy oil, oil sands, enhanced oil recovery and LNG. Earnings from Technology increased by $14 million in 2019 compared with 2018, primarily due to higher licensing revenues.

The category "Other" includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, other costs not directly associated with an operating segment, premiums incurred on the early retirement of debt, unrealized holding gains or losses on equity securities, and pension settlement expense. Earnings in "Other" increased by $1,776 million in 2019 compared with 2018, primarily due to an unrealized gain of $649 million after-tax on our CVE common shares in 2019, and the absence of a $436 million after-tax unrealized loss on those shares in 2018. Additionally, earnings increased due to the absence of $195 million in premiums on the early retirement of debt, lower pension settlement expense, and a $151 million tax benefit related to the revaluation of deferred tax assets following finalization of rules related to the 2017 Tax Cuts and Jobs Act. See Note 19—Income Taxes, in the Notes to Consolidated Financial Statements, for additional information related to the 2017 Tax Cuts and Jobs Act.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

		Millions of Dollars Except as Indicated		
		2019	2018	2017
Net cash provided by operating activities	$	**11,104**	12,934	7,077
Cash and cash equivalents		**5,088**	5,915	6,325
Short-term debt		**105**	112	2,575
Total debt		**14,895**	14,968	19,703
Total equity		**35,050**	32,064	30,801
Percent of total debt to capital*		**30 %**	32	39
Percent of floating-rate debt to total debt		**5 %**	5	5

**Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources, including cash generated from operating activities, proceeds from asset sales, our commercial paper and credit facility programs and our ability to sell securities using our shelf registration statement. In 2019, the primary uses of our available cash were $6,636 million to support our ongoing capital expenditures and investments program; $3,500 million to repurchase our common stock; $2,910 million net purchases of investments, and $1,500 million to pay dividends on our common stock. During 2019, cash and cash equivalents decreased by $827 million to $5,088 million.

We believe current cash balances and cash generated by operations, together with access to external sources of funds as described below in the “Significant Changes in Capital” section, will be sufficient to meet our funding requirements in the near and long term, including our capital spending program, share repurchases, dividend payments and required debt payments.

Our commitment to disciplined execution of these funding requirements includes cash investment strategies that position us for success in an environment of short-term price volatility as well as extended downturns in commodity prices. The primary objectives of these cash investment strategies in priority order are to protect principal, maintain liquidity, and provide yield and total returns. Funds for short-term needs to support our operating plan and provide resiliency to react to short-term price volatility are invested in highly liquid instruments with maturities within the year. Funds we consider available to maintain resiliency in longer term price downturns and to capture opportunities outside a given operating plan may be invested in instruments with maturities greater than one year. For additional information, see Note 1–Accounting Policies and Note 14–Derivative and Financial Instruments.

Significant Changes in Capital

Operating Activities

During 2019, cash provided by operating activities was $11,104 million, a 14 percent decrease from 2018. The decrease was primarily due to lower prices, lower collections related to settlements reached with Ecuador and PDVSA, and a pension contribution made in conjunction with the sale of two U.K. subsidiaries, partially offset by higher volumes.

While the stability of our cash flows from operating activities benefits from geographic diversity, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, bitumen, natural gas, LNG and NGLs. Prices and margins in our industry have historically been volatile and are driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level of absolute production volumes, as well as product and location mix, impacts our cash flows. Full-year production averaged 1,348 MBOED in 2019. Full-year production excluding Libya averaged 1,305 MBOED in 2019 and is expected to be 1,230 to 1,270 MBOED in 2020. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact investment decisions; the effects of price changes on production sharing and variable-royalty contracts; acquisition and disposition of fields; field production decline rates; new technologies; operating efficiencies; timing of startups and major turnarounds; political instability; weather-related disruptions; and the addition of proved reserves through exploratory success and their timely and cost-effective development. While we actively manage these factors, production levels can cause variability in cash flows, although generally this variability has not been as significant as that caused by commodity prices.

To maintain or grow our production volumes on an ongoing basis, we must continue to add to our proved reserve base. Our proved reserves generally increase as prices rise and decrease as prices decline. In 2019, our reserve replacement, which included a net decrease of 0.1 billion BOE from sales and purchases, was 100 percent. Increased crude oil reserves accounted for approximately 55 percent of the total change in reserves. Our organic reserve replacement, which excludes the impact of sales and purchases, was 117 percent in 2019. Approximately 51 percent of organic reserve additions are from Lower 48, 13 percent from Alaska, 12 percent from Canada, 12 percent from Europe and North Africa and 12 percent from Asia Pacific and Middle East.

In the five years ended December 31, 2019, our reserve replacement, which included a decrease of 2.0 billion BOE from sales and purchases, was negative 34 percent, reflecting the impact of asset dispositions and lower prices during that period. Our organic reserve replacement during the five years ended December 31, 2019, was 40 percent, reflecting development activities as well as lower prices during that period.

Historically our reserve replacement has varied considerably year to year contingent upon the timing of major projects which may have long lead times between capital investment and production. In the last several years, more of our capital has been allocated to short cycle time, onshore, unconventional plays. Accordingly, we believe our recent success in replacing reserves can be viewed on a trailing three-year basis.

In the three years ended December 31, 2019, our reserve replacement was 23 percent, reflecting the impact of asset dispositions during that period. Our organic reserve replacement during the three years ended December 31, 2019, which excludes a decrease of 1.8 billion BOE related to sales and purchases, was 143 percent, reflecting reserve additions from development activities.

Reserve replacement represents the net change in proved reserves, net of production, divided by our current year production, as shown in our supplemental reserve table disclosures. For additional information about our 2020 capital budget, see the “2020 Capital Budget” section within “Capital Resources and Liquidity” and for additional information on proved reserves, including both developed and undeveloped reserves, see the “Oil and Gas Operations” section of this report.

As discussed in the “Critical Accounting Estimates” section, engineering estimates of proved reserves are imprecise; therefore, each year reserves may be revised upward or downward due to the impact of changes in commodity prices or as more technical data becomes available on reservoirs. We have reported revisions as increases to reserves in the current period, however in prior periods, reported revisions as decreases to reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

Investing Activities
Proceeds from asset sales in 2019 were $3.0 billion. We completed the sale of two ConocoPhillips U.K. subsidiaries to Chrysaor E&P Limited for $2.2 billion. We also completed the sale of several assets including our 30 percent interest in the Greater Sunrise Fields for $350 million and received $106 million of contingent payments from Cenovus Energy.

In the fourth quarter of 2019, we entered into an agreement to sell the subsidiaries that hold our Australia-West assets and operations to Santos for $1.39 billion, plus customary adjustments. In addition, we will receive a payment of $75 million upon final investment decision of the Barossa development project. Also in the fourth quarter of 2019, we signed an agreement to sell our interests in the Niobrara shale play for $380 million, plus customary adjustments, and overriding royalty interests in certain future wells. Both transactions are subject to regulatory approval and other conditions precedent and expected to close in the first quarter of 2020.

Investing activities in 2019 also included net purchases of $2.9 billion of investments in short-term and long-term financial instruments. These investments include time deposits, commercial paper as well as debt securities classified as available for sale. The investment in short-term instruments was $2.8 billion, the remaining $0.1 billion was invested in long-term debt securities. For additional information, see Note 14–Derivative and Financial Instruments.

Proceeds from asset sales in 2018 were $1.1 billion. We completed several undeveloped acreage transactions in our Lower 48 segment for a total of $267 million after customary adjustments and another transaction in our Lower 48 segment for $112 million after customary adjustments. We completed the sale of our interests in the Barnett to Lime Rock Resources for $196 million after customary adjustments. We also completed the sale of a ConocoPhillips subsidiary to BP and received $253 million net proceeds. The subsidiary held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the U.K. During 2018, we received $95 million of contingent payments from Cenovus Energy.

For additional information on our dispositions, see Note 5—Asset Acquisitions and Dispositions in the Notes to Consolidated Financial Statements.

Commercial Paper and Credit Facilities

We have a revolving credit facility totaling $6.0 billion, expiring in May 2023. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper program. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the U.S. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

The revolving credit facility supports the ConocoPhillips Company $6.0 billion commercial paper program, which is primarily a funding source for short-term working capital needs. Commercial paper maturities are generally limited to 90 days. We had no commercial paper outstanding in programs in place at December 31, 2019 or December 31, 2018. We had no direct outstanding borrowings or letters of credit under the revolving credit facility at December 31, 2019 and December 31, 2018. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.0 billion in borrowing capacity under our revolving credit facility at December 31, 2019.

Our current long-term debt ratings remained unchanged in 2019 and are as follows: Fitch - “A” with a “stable” outlook; Moody’s Investors Services - “A3” with a “stable” outlook; and Standard & Poor’s - “A” with a stable outlook. We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, in the event of a downgrade of our credit rating. If our credit rating were downgraded, it could increase the cost of corporate debt available to us and restrict our access to the commercial paper markets. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our revolving credit facility.

Certain of our project-related contracts, commercial contracts and derivative instruments contain provisions requiring us to post collateral. Many of these contracts and instruments permit us to post either cash or letters of credit as collateral. At December 31, 2019 and 2018, we had direct bank letters of credit of $277 million and $323 million, respectively, which secured performance obligations related to various purchase commitments incident to the ordinary conduct of business. In the event of credit ratings downgrades, we may be required to post additional letters of credit.

Shelf Registration
We have a universal shelf registration statement on file with the SEC under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

Off-Balance Sheet Arrangements

As part of our normal ongoing business operations and consistent with normal industry practice, we enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements.

For information about guarantees, see Note 12—Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Capital Requirements

For information about our capital expenditures and investments, see the "Capital Expenditures" section.

Our debt balance at December 31, 2019, was $14,895 million, a decrease of $73 million from the balance at December 31, 2018. For more information on Debt, see Note 11—Debt, in the Notes to Consolidated Financial Statements.

On January 30, 2019, we announced a quarterly dividend of $0.305 per share. The dividend was paid on March 1, 2019, to stockholders of record at the close of business on February 11, 2019. On May 1, 2019, we announced a quarterly dividend of $0.305 per share. The dividend was paid on June 3, 2019, to stockholders of record at the close of business on May 13, 2019. On July 11, 2019, we announced a quarterly dividend of $0.305 per share. The dividend was paid on September 3, 2019, to stockholders of record at the close of business on July 22, 2019. On October 7, 2019, we announced a 38 percent increase in the quarterly dividend to $0.42 per share. The dividend was paid on December 2, 2019, to stockholders of record at the close of business on October 17, 2019. In February 2020, we announced a quarterly dividend of $0.42 per share, payable March 2, 2020, to stockholders of record at the close of business on February 14, 2020.

In late 2016, we initiated our current share repurchase program. As of December 31, 2019, we had announced a total authorization to repurchase $15 billion of our common stock. We repurchased $3 billion in 2017, $3 billion in 2018 and $3.5 billion in 2019. Of the remaining authorization, we expect to repurchase $3 billion in 2020. In February 2020, we announced that the Board of Directors approved an increase to our authorization from $15 billion to $25 billion, to support our plan for future share repurchases. Whether we undertake these additional repurchases is ultimately subject to numerous considerations, market conditions and other factors. See Risk Factors -"Our ability to declare and pay dividends and repurchase shares is subject to certain considerations." Since our share repurchase program began in November 2016, we have repurchased 169 million shares at a cost of $9.6 billion through December 31, 2019.

Contractual Obligations

The table below summarizes our aggregate contractual fixed and variable obligations as of December 31, 2019:

	Millions of Dollars				
	Payments Due by Period				
	Total	Up to 1 Year	Years 2–3	Years 4–5	After 5 Years
Debt obligations (a)	$ 14,175	18	1,018	605	12,534
Finance lease obligations (b)	720	87	157	141	335
Total debt	14,895	105	1,175	746	12,869
Interest on debt	11,339	856	1,671	1,603	7,209
Operating lease obligations (c)	1,050	379	377	145	149
Purchase obligations (d)	8,671	3,237	1,745	1,327	2,362
Other long-term liabilities					
Pension and postretirement benefit contributions (e)	1,375	440	540	395	-
Asset retirement obligations (f)	6,206	997	282	309	4,618
Accrued environmental costs (g)	171	28	33	21	89
Unrecognized tax benefits (h)	82	82	(h)	(h)	(h)
Total	$ 43,789	6,124	5,823	4,546	27,296

(a) Includes $204 million of net unamortized premiums, discounts and debt issuance costs. See Note 11—Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) See Note 17—Non-Mineral Leases, in the Notes to Consolidated Financial Statements, for additional information.

(c) Includes $31 million of short-term leases that are not recorded on our consolidated balance sheet. See Note 17—Non-Mineral Leases, in the Notes to Consolidated Financial Statements, for additional information.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms, presented on an undiscounted basis. Does not include purchase commitments for jointly owned fields and facilities where we are not the operator.

The majority of the purchase obligations are market-based contracts related to our commodity business. Product purchase commitments with third parties totaled $2,426 million.

Purchase obligations of $5,111 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG and product terminals, to transport, process, treat and store commodities. The remainder is primarily our net share of purchase commitments for materials and services for jointly owned fields and facilities where we are the operator.

(e) Represents contributions to qualified and nonqualified pension and postretirement benefit plans for the years 2020 through 2024. For additional information related to expected benefit payments subsequent to 2024, see Note 18—Employee Benefit Plans, in the Notes to Consolidated Financial Statements.

(f) Represents estimated discounted costs to retire and remove long-lived assets at the end of their operations.

(g) Represents estimated costs for accrued environmental expenditures presented on a discounted basis for costs acquired in various business combinations and an undiscounted basis for all other accrued environmental costs.

(h) Excludes unrecognized tax benefits of $1,095 million because the ultimate disposition and timing of any payments to be made with regard to such amounts are not reasonably estimable. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

Capital Expenditures and Investments

	Millions of Dollars		
	2019	2018	2017
Alaska	$ **1,513**	1,298	815
Lower 48	**3,394**	3,184	2,136
Canada	**368**	477	202
Europe and North Africa	**708**	877	872
Asia Pacific and Middle East	**584**	718	482
Other International	**8**	6	21
Corporate and Other	**61**	190	63
Capital Program	$ **6,636**	6,750	4,591

Our capital expenditures and investments for the three-year period ended December 31, 2019, totaled $18.0 billion. The 2019 expenditures supported key exploration and developments, primarily:

- Development, appraisal and exploration activities in the Lower 48, including Eagle Ford, Permian Unconventional, and Bakken.
- Appraisal and development activities in Alaska related to the Western North Slope; development activities in the Greater Kuparuk Area and the Greater Prudhoe Area; leasehold acquisition in the Greater Kuparuk Area.
- Development activities across assets in Norway, as well as for assets in the U.K. that recently have been sold.
- Optimization of oil sands development and appraisal activities in liquids-rich plays in Canada.
- Signature bonus for Indonesia Corridor Block production sharing contract, as well as continued development in China, Malaysia, Australia, and Indonesia.

2020 CAPITAL BUDGET

In February 2020, we announced 2020 operating plan capital of $6.5 billion to $6.7 billion. The plan includes funding for ongoing development drilling programs, major projects, exploration and appraisal activities, as well as base maintenance. Capital spend is expected to be higher in the first quarter largely from winter construction and exploration and appraisal drilling in Alaska. This guidance does not include capital for acquisitions.

For information on PUDs and the associated costs to develop these reserves, see the "Oil and Gas Operations" section in this report.

Contingencies
A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active

and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. For information on other contingencies, see "Critical Accounting Estimates" and Note 13—Contingencies and Commitments, in the Notes to Consolidated Financial Statements.

Legal and Tax Matters
We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, climate change, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required. See Note 19—Income Taxes, in the Notes to Consolidated Financial Statements, for additional information about income tax-related contingencies.

Environmental
We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. The most significant of these environmental laws and regulations include, among others, the:

- U.S. Federal Clean Air Act, which governs air emissions.
- U.S. Federal Clean Water Act, which governs discharges to water bodies.
- European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH).
- U.S. Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or Superfund), which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur.
- U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage and disposal of solid waste.
- U.S. Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the U.S.
- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments.

- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.
- European Union Trading Directive resulting in European Emissions Trading Scheme.

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits and establish standards and impose obligations for the remediation of releases of hazardous substances and hazardous wastes. They also, in most cases, require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time consuming. In addition, there can be delays associated with notice and comment periods and the agency's processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

Many states and foreign countries where we operate also have, or are developing, similar environmental laws and regulations governing these same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards and water quality standards, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, are expected to continue to have an increasing impact on our operations in the U.S. and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the U.S. and Canada.

An example is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower permeability rock formations. A range of local, state, federal or national laws and regulations currently govern hydraulic fracturing operations, with hydraulic fracturing currently prohibited in some jurisdictions. Although hydraulic fracturing has been conducted for many decades, a number of new laws, regulations and permitting requirements are under consideration by various state environmental agencies, and others which could result in increased costs, operating restrictions, operational delays and/or limit the ability to develop oil and natural gas resources. Governmental restrictions on hydraulic fracturing could impact the overall profitability or viability of certain of our oil and natural gas investments. We have adopted operating principles that incorporate established industry standards designed to meet or exceed government requirements. Our practices continually evolve as technology improves and regulations change.

We also are subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Longer-term expenditures are subject to considerable uncertainty and may fluctuate significantly.

We occasionally receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2019, there were 15 sites around the U.S. in which we were identified as a potentially responsible party under CERCLA and comparable state laws.

For most Superfund sites, our potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to us, versus that attributable to all other potentially responsible parties, is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where we are a party typically have had the financial strength to meet their obligations, and where they have not, or where potentially responsible parties could not be located, our share of liability has not increased materially. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or attain a settlement of liability. Actual cleanup costs generally occur after the parties obtain EPA or equivalent state agency approval. There are relatively few sites where we are a major participant, and given the timing and amounts of anticipated expenditures, neither the cost of remediation at those sites nor such costs at all CERCLA sites, in the aggregate, is expected to have a material adverse effect on our competitive or financial condition.

Expensed environmental costs were $511 million in 2019 and are expected to be about $545 million per year in 2020 and 2021. Capitalized environmental costs were $194 million in 2019 and are expected to be about $225 million per year in 2020 and 2021.

Accrued liabilities for remediation activities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

Many of these liabilities result from CERCLA, RCRA and similar state or international laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or other agency enforcement activities. The laws that require or address environmental remediation may apply retroactively and regardless of fault, the legality of the original activities or the current ownership or control of sites. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA.

Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At December 31, 2019, our balance sheet included total accrued environmental costs of $171 million, compared with $178 million at December 31, 2018, for remediation activities in the U.S. and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent concerns in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect upon our results of operations or financial position as a result of compliance with current environmental laws and regulations.

Climate Change

Continuing political and social attention to the issue of global climate change has resulted in a broad range of proposed or promulgated state, national and international laws focusing on GHG reduction. These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our results of operations and financial condition. Examples of legislation or precursors for possible regulation that do or could affect our operations include:

- European Emissions Trading Scheme (ETS), the program through which many of the EU member states are implementing the Kyoto Protocol. Our cost of compliance with the EU ETS in 2019 was approximately $8 million before-tax.
- The Alberta Carbon Competitiveness Incentive Regulation (CCIR) requires any existing facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide, or equivalent, per year to meet an industry benchmark intensity. The total cost of these regulations in 2019 was approximately $4 million.
- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007), confirmed that the EPA has the authority to regulate carbon dioxide as an “air pollutant” under the Federal Clean Air Act.
- The U.S. EPA’s announcement on March 29, 2010 (published as “Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs,” 75 Fed. Reg. 17004 (April 2, 2010)), and the EPA’s and U.S. Department of Transportation’s joint promulgation of a Final Rule on April 1, 2010, that triggers regulation of GHGs under the Clean Air Act, may trigger more climate-based claims for damages, and may result in longer agency review time for development projects.
- The U.S. EPA’s announcement on January 14, 2015, outlining a series of steps it plans to take to address methane and smog-forming volatile organic compound emissions from the oil and gas industry. The former U.S. administration established a goal of reducing the 2012 levels in methane emissions from the oil and gas industry by 40 to 45 percent by 2025.
- Carbon taxes in certain jurisdictions. Our cost of compliance with Norwegian carbon tax legislation in 2019 was approximately $30 million (net share before-tax). We also incur a carbon tax for emissions from fossil fuel combustion in our British Columbia and Alberta Operations totaling just over $0.8 million (net share before-tax).
- The agreement reached in Paris in December 2015 at the 21st Conference of the Parties to the United Nations Framework on Climate Change, setting out a new process for achieving global emission reductions. While the U.S. announced its intention to withdraw from the Paris Agreement, there is no guarantee that the commitments made by the U.S. will not be implemented, in whole or in part, by U.S. state and local governments or by major corporations headquartered in the U.S.

In the U.S., some additional form of regulation may be forthcoming in the future at the federal and state levels with respect to GHG emissions. Such regulation could take any of several forms that may result in the creation of additional costs in the form of taxes, the restriction of output, investments of capital to maintain compliance with laws and regulations, or required acquisition or trading of emission allowances. We are working to continuously improve operational and energy efficiency through resource and energy conservation throughout our operations.

Compliance with changes in laws and regulations that create a GHG tax, emission trading scheme or GHG reduction policies could significantly increase our costs, reduce demand for fossil energy derived products, impact the cost and availability of capital and increase our exposure to litigation. Such laws and regulations could also increase demand for less carbon intensive energy sources, including natural gas. The ultimate impact on our financial performance, either positive or negative, will depend on a number of factors, including but not limited to:

- Whether and to what extent legislation or regulation is enacted.
- The timing of the introduction of such legislation or regulation.

- The nature of the legislation (such as a cap and trade system or a tax on emissions) or regulation.
- The price placed on GHG emissions (either by the market or through a tax).
- The GHG reductions required.
- The price and availability of offsets.
- The amount and allocation of allowances.
- Technological and scientific developments leading to new products or services.
- Any potential significant physical effects of climate change (such as increased severe weather events, changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices of our products and services.

The company has responded by putting in place a Sustainable Development Risk Management Standard covering the assessment and registering of significant and high sustainable development risks based on their consequence and likelihood of occurrence. We have developed a company-wide Climate Change Action Plan with the goal of tracking mitigation activities for each climate-related risk included in the corporate Sustainable Development Risk Register.

The risks addressed in our Climate Change Action Plan fall into four broad categories:

- GHG-related legislation and regulation.
- GHG emissions management.
- Physical climate-related impacts.
- Climate-related disclosure and reporting.

Emissions are categorized into different scopes. Scope 1 and Scope 2 GHG emissions help us understand climate transition risk. Scope 1 emissions are direct GHG emissions from sources that we own or control. Scope 2 emissions are GHG emissions from the generation of purchased electricity or steam that we consume.

Our corporate authorization process requires all qualifying projects to run a GHG pricing sensitivity using a corporate price of $40 per tonne of carbon dioxide equivalent, plus annual inflation, for all Scope 1 and Scope 2 GHG emissions produced in 2024 and later. Projects in jurisdictions with existing GHG pricing regimes must incorporate that existing GHG price and its forecast into their base case economics. Where the existing GHG price is below the corporate price, the $40 per tonne of carbon dioxide equivalent sensitivity must also be run from 2024 onward. Thus, both existing and emerging regulatory requirements are considered in our decision-making. The company does not use an estimated market cost of GHG emissions when assessing reserves in jurisdictions without existing GHG regulations.

In December 2018, we became a founding member of the CLC, an international policy institute founded in collaboration with business and environmental interests to develop a carbon dividend plan. Participation in the CLC provides another opportunity for ongoing dialogue about carbon pricing and framing the issues in alignment with our public policy principles. We also belong to and fund Americans For Carbon Dividends, the education and advocacy branch of the CLC.

In 2017 and 2018, cities, counties, and a state government in California, New York, Washington, Rhode Island and Maryland, as well as the Pacific Coast Federation of Fishermen's Association, Inc., have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. ConocoPhillips is vigorously defending against these lawsuits. The lawsuits brought by the Cities of San Francisco, Oakland and New York have been dismissed by the district courts and appeals are pending. Lawsuits filed by other cities and counties in California and Washington are currently stayed pending resolution of the appeals brought by the Cities of San Francisco and Oakland to the U.S. Court of Appeals for the Ninth Circuit. Lawsuits filed in Maryland and Rhode Island are proceeding in state court while rulings in those matters, on the issue of whether the matters should proceed in state or federal court, are on appeal to the U.S. Court of Appeals for the Fourth Circuit and First Circuit, respectively.

Several Louisiana parishes and individual landowners have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages in connection with historical oil and gas operations in Louisiana. All parish lawsuits are stayed pending an appeal to the Fifth Circuit Court of Appeals on the issue of whether they will proceed in federal or state court. ConocoPhillips will vigorously defend against these lawsuits.

Other

We have deferred tax assets related to certain accrued liabilities, loss carryforwards and credit carryforwards. Valuation allowances have been established to reduce these deferred tax assets to an amount that will, more likely than not, be realized. Based on our historical taxable income, our expectations for the future, and available tax-planning strategies, management expects the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with GAAP requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See Note 1—Accounting Policies, in the Notes to Consolidated Financial Statements, for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting estimates are discussed with the Audit and Finance Committee of the Board of Directors at least annually. We believe the following discussions of critical accounting estimates, along with the discussion of deferred tax asset valuation allowances in this report, address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

Oil and Gas Accounting

Accounting for oil and gas exploratory activity is subject to special accounting rules unique to the oil and gas industry. The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet pending determination of whether proved oil and gas reserves have been recognized.

Property Acquisition Costs

For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For relatively small individual leasehold acquisition costs, management exercises judgment and determines a percentage probability that the prospect ultimately will fail to find proved oil and gas reserves and pools that leasehold information with others in the geographic area. For prospects in areas with limited, or no, previous exploratory drilling, the percentage probability of ultimate failure is normally judged to be quite high. This judgmental percentage is multiplied by the leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to determine a periodic leasehold impairment charge that is reported in exploration expense. This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively.

At year-end 2019, the remaining $3.5 billion of net capitalized unproved property costs consisted primarily of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently being drilled, suspended exploratory wells, and capitalized interest. Of this amount, approximately $2.1 billion is concentrated in 10 major development areas, the majority of which are not expected to move to proved properties in 2020, and $0.6 billion is held for sale. Management periodically assesses individually significant leaseholds for impairment based on the results of exploration and drilling efforts and the outlook for commercialization.

Exploratory Costs

For exploratory wells, drilling costs are temporarily capitalized, or "suspended," on the balance sheet, pending a determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort to justify development.

If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of "sufficient progress" is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the expectation future market conditions will improve or new technologies will be found that would make the development economically profitable. Often, the ability to move into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as we are actively pursuing such approvals and permits, and believe they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once a determination is made the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and reported in exploration expense.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as a dry hole when it determines the potential field does not warrant further investment in the near term. Criteria utilized in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected development costs, ability to apply existing technology to produce the reserves, fiscal terms, regulations or contract negotiations, and our expected return on investment.

At year-end 2019, total suspended well costs were $1,020 million, compared with $856 million at year-end 2018. For additional information on suspended wells, including an aging analysis, see Note 8—Suspended Wells and Other Exploration Expenses, in the Notes to Consolidated Financial Statements.

Proved Reserves

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. Reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and approved operating limits. 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.

Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of "proved" reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company's operations. There are several authoritative guidelines regarding the engineering criteria that must be met before estimated reserves can be designated as "proved." Our geosciences and reservoir engineering organization has policies and procedures in place consistent with these authoritative guidelines. We have trained and experienced internal engineering personnel who estimate our proved reserves held by consolidated companies, as well as our share of equity affiliates.

Proved reserve estimates are adjusted annually in the fourth quarter and during the year if significant changes occur, and take into account recent production and subsurface information about each field. Also, as required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on 12-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to PSCs, reported under the "economic interest" method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. We would expect reserves from these contracts to decrease when product prices rise and increase when prices decline.

The estimation of proved developed reserves also is important to the income statement because the proved developed reserve estimate for a field serves as the denominator in the unit-of-production calculation of the DD&A of the capitalized costs for that asset. At year-end 2019, the net book value of productive PP&E subject to a unit-of-production calculation was approximately $35 billion and the DD&A recorded on these assets in 2019 was approximately $5.8 billion. The estimated proved developed reserves for our consolidated operations were 3.3 billion BOE at the end of 2018 and 3.2 billion BOE at the end of 2019. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 10 percent across all calculations, before-tax DD&A in 2019 would have increased by an estimated $642 million.

Impairments

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted before-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for E&P assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, commodity prices, operating costs and capital decisions, considering all available information at the date of review. Differing assumptions could affect the timing and the amount of an impairment in any period. See Note 9—Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment when there is evidence of a loss in value and annually following updates to corporate planning assumptions. Such evidence of a loss in value might include our inability to recover the carrying amount, the lack of sustained earnings capacity which would justify the current investment amount, or a current fair value less than the investment's carrying amount. When it is determined such a loss in value is other than temporary, an impairment charge is recognized for the difference between the investment's carrying value and its estimated fair value. When determining whether a decline in value is other than temporary, management considers factors such as the length of time and extent of the decline, the investee's financial condition and near-term prospects, and our ability and intention to retain our investment for a period that will be sufficient to allow for any anticipated recovery in the market value of the investment. Since quoted market prices are usually not available, the fair value is typically based on the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate. Differing assumptions could affect the timing and the amount of an impairment of an investment in any period. See the "APLNG" section of Note 6—Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for additional information.

Asset Retirement Obligations and Environmental Costs

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve plugging and abandonment of wells, removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. The fair values of obligations for dismantling and removing these facilities are recorded as a liability and an increase to PP&E at the time of installation of the asset based on estimated discounted costs. Estimating future asset removal costs is difficult. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. Asset removal technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, are also subject to change.

Normally, changes in asset removal obligations are reflected in the income statement as increases or decreases to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations, as well as previously sold assets for which we retained the asset removal obligation, an increase in the asset removal obligation can result in an immediate charge to earnings, because any increase in PP&E due to the increased obligation would immediately be subject to impairment, due to the low fair value of these properties.

In addition to asset removal obligations, under the above or similar contracts, permits and regulations, we have certain environmental-related projects. These are primarily related to remediation activities required by Canada and various states within the U.S. at exploration and production sites. Future environmental remediation costs are difficult to estimate because they are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. See Note 10—Asset Retirement Obligations and Accrued Environmental Costs, in the Notes to Consolidated Financial Statements, for additional information.

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. For Employee Retirement Income Security Act-governed pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into the plans. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all vested benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Projected benefit obligations are particularly sensitive to the discount rate assumption. A 100 basis-point decrease in the discount rate assumption would increase projected benefit obligations by $1,000 million. Benefit expense is sensitive to the discount rate and return on plan assets assumptions. A 100 basis-point decrease in the discount rate assumption would increase annual benefit expense by $100 million, while a 100 basis-point decrease in the return on plan assets assumption would increase annual benefit expense by $60 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans. We are also exposed to the possibility that lump sum retirement benefits taken from pension plans during the year could exceed the total of service and interest components of annual pension expense and trigger accelerated recognition of a portion of unrecognized net actuarial losses and gains. These benefit payments are based on decisions by plan participants and are therefore difficult to predict. In the event there is a significant reduction in the expected years of future service of present employees or the elimination of the accrual of defined benefits for some or all of their future services for a significant number of employees, we could recognize a curtailment gain or loss. See Note 18—Employee Benefit Plans, in the Notes to Consolidated Financial Statements, for additional information.

Contingencies
A number of claims and lawsuits are made against the company arising in the ordinary course of business. Management exercises judgment related to accounting and disclosure of these claims which includes losses, damages, and underpayments associated with environmental remediation, tax, contracts, and other legal disputes. As we learn new facts concerning contingencies, we reassess our position both with respect to amounts recognized and disclosed considering changes to the probability of additional losses and potential exposure. However, actual losses can and do vary from estimates for a variety of reasons including legal, arbitration, or other third-party decisions; settlement discussions; evaluation of scope of damages; interpretation of regulatory or contractual terms; expected timing of future actions; and proportion of liability shared with other responsible parties. Estimated future costs related to contingencies are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes. For additional information on contingent liabilities, see the “Contingencies” section within “Capital Resources and Liquidity” and Note 13—Contingencies and Commitments.

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans, and objectives of management for future operations, are forward-looking statements. Examples of forward-looking statements contained in this report include our expected production growth and outlook on the business environment generally, our expected capital budget and capital expenditures, and discussions concerning future dividends. You can often identify our forward-looking statements by the words "anticipate," "estimate," "believe," "budget," "continue," "could," "intend," "may," "plan," "potential," "predict," "seek," "should," "will," "would," "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions.

We based the forward-looking statements on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including, but not limited to, the following:

- Fluctuations in crude oil, bitumen, natural gas, LNG and NGLs prices, including a prolonged decline in these prices relative to historical or future expected levels.
- The impact of significant declines in prices for crude oil, bitumen, natural gas, LNG and NGLs, which may result in recognition of impairment costs on our long-lived assets, leaseholds and nonconsolidated equity investments.
- Potential failures or delays in achieving expected reserve or production levels from existing and future oil and gas developments, including due to operating hazards, drilling risks and the inherent uncertainties in predicting reserves and reservoir performance.
- Reductions in reserves replacement rates, whether as a result of the significant declines in commodity prices or otherwise.
- Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating E&P facilities.
- Legislative and regulatory initiatives addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, bitumen, natural gas, LNG and NGLs.
- Inability to timely obtain or maintain permits, including those necessary for construction, drilling and/or development, or inability to make capital expenditures required to maintain compliance with any necessary permits or applicable laws or regulations.
- Failure to complete definitive agreements and feasibility studies for, and to complete construction of, announced and future exploration and production and LNG development in a timely manner (if at all) or on budget.
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events, war, global health epidemics, terrorism, cyber attacks, and information technology failures, constraints or disruptions.
- Changes in international monetary conditions and foreign currency exchange rate fluctuations.

- Changes in international trade relationships, including the imposition of trade restrictions or tariffs relating to crude oil, bitumen, natural gas, LNG, NGLs and any materials or products (such as aluminum and steel) used in the operation of our business.
- Substantial investment in and development use of, competing or alternative energy sources, including as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under existing or future environmental regulations and litigation.
- Significant operational or investment changes imposed by existing or future environmental statutes and regulations, including international agreements and national or regional legislation and regulatory measures to limit or reduce GHG emissions.
- Liability resulting from litigation or our failure to comply with applicable laws and regulations.
- General domestic and international economic and political developments, including armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, bitumen, natural gas, LNG and NGLs pricing, regulation or taxation; the impact of and uncertainty surrounding the U.K.'s decision to withdraw from the EU; and other political, economic or diplomatic developments.
- Volatility in the commodity futures markets.
- Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business, including changes resulting from the implementation and interpretation of the Tax Cuts and Jobs Act.
- Competition and consolidation in the oil and gas E&P industry.
- Any limitations on our access to capital or increase in our cost of capital, including as a result of illiquidity or uncertainty in domestic or international financial markets.
- Our inability to execute, or delays in the completion, of any asset dispositions or acquisitions we elect to pursue.
- Potential failure to obtain, or delays in obtaining, any necessary regulatory approvals for asset dispositions or acquisitions, or that such approvals may require modification to the terms of the transactions or the operation of our remaining business.
- Potential disruption of our operations as a result of asset dispositions or acquisitions, including the diversion of management time and attention.
- Our inability to deploy the net proceeds from any asset dispositions we undertake in the manner and timeframe we currently anticipate, if at all.
- Our inability to liquidate the common stock issued to us by Cenovus Energy as part of our sale of certain assets in western Canada at prices we deem acceptable, or at all.
- The operation and financing of our joint ventures.
- The ability of our customers and other contractual counterparties to satisfy their obligations to us, including our ability to collect payments when due from the government of Venezuela or PDVSA.
- Our inability to realize anticipated cost savings and expenditure reductions.
- The factors generally described in Item 1A—Risk Factors in this 2019 Annual Report on Form 10-K and any additional risks described in our other filings with the SEC.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Financial Instrument Market Risk

We and certain of our subsidiaries hold and issue derivative contracts and financial instruments that expose our cash flows or earnings to changes in commodity prices, foreign currency exchange rates or interest rates. We may use financial and commodity-based derivative contracts to manage the risks produced by changes in the prices of natural gas, crude oil and related products; fluctuations in interest rates and foreign currency exchange rates; or to capture market opportunities.

Our use of derivative instruments is governed by an “Authority Limitations” document approved by our Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity. The Authority Limitations document also establishes the Value at Risk (VaR) limits for the company, and compliance with these limits is monitored daily. The Executive Vice President and Chief Financial Officer, who reports to the Chief Executive Officer, monitors commodity price risk and risks resulting from foreign currency exchange rates and interest rates. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, and monitors risks.

Commodity Price Risk
Our Commercial organization uses futures, forwards, swaps and options in various markets to accomplish the following objectives:

- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas consumers, to floating market prices.
- Enable us to use market knowledge to capture opportunities such as moving physical commodities to more profitable locations and storing commodities to capture seasonal or time premiums. We may use derivatives to optimize these activities.

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments we hold or issue, including commodity purchases and sales contracts recorded on the balance sheet at December 31, 2019, as derivative instruments. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes or held for purposes other than trading at December 31, 2019 and 2018, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips.

Interest Rate Risk
The following table provides information about our debt instruments that are sensitive to changes in U.S. interest rates. The table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on effective rates at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data.

Expected Maturity Date	Millions of Dollars Except as Indicated Debt Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate
Year-End 2019				
2020	**$ -**	**- %**	**$ -**	**- %**
2021	**140**	**6.24**	**-**	**-**
2022	**343**	**2.54**	**500**	**2.81**
2023	**106**	**7.20**	**-**	**-**
2024	**456**	**3.52**	**-**	**-**
Remaining years	**12,143**	**6.25**	**283**	**1.65**
Total	**$ 13,188**		**$ 783**	
Fair value	**$ 17,325**		**$ 783**	
Year-End 2018				
2019	$ 17	- %	$ -	- %
2020	-	-	-	-
2021	123	9.13	-	-
2022	343	2.54	500	3.52
2023	106	7.20	-	-
Remaining years	12,599	6.16	283	1.78
Total	$ 13,188		$ 783	
Fair value	$ 15,364		$ 783	

Foreign Currency Exchange Risk

We have foreign currency exchange rate risk resulting from international operations. We do not comprehensively hedge the exposure to currency exchange rate changes although we may choose to selectively hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or local currency tax payments, dividends and cash returns from net investments in foreign affiliates to be remitted within the coming year, and investments in equity securities.

At December 31, 2019 and 2018, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps and options for purposes of mitigating our cash-related exposures. Although these forwards, swaps and options hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting. As a result, the change in the fair value of these foreign currency exchange derivatives is recorded directly in earnings.

At December 31, 2019, we had outstanding foreign currency exchange forward contracts to sell $1.35 billion CAD at $0.748 CAD against the U.S. dollar. At December 31, 2018, we had outstanding foreign currency zero-cost collars buying the right to sell $1.25 billion CAD at $0.707 CAD and selling the right to buy $1.25 billion CAD at $0.842 CAD against the U.S. dollar. Based on the assumed volatility in the fair value calculation, the net fair value of these foreign currency contracts at December 31, 2019 and December 31, 2018, was a before-tax loss of $28 million and a before-tax gain of $6 million, respectively. Based on an adverse hypothetical 10 percent change in the December 2019 and December 2018 exchange rate, this would result in an additional before-tax loss of $115 million and $17 million, respectively. The sensitivity analysis is based on changing one assumption while holding all other assumptions constant, which in practice may be unlikely to occur, as changes in some of the assumptions may be correlated.

The gross notional and fair value of these positions at December 31, 2019 and 2018, were as follows:

Foreign Currency Exchange Derivatives		In Millions			
		Notional*		Fair Value**	
		2019	2018	**2019**	2018
Sell U.S. dollar, buy British pound	USD	-	805	-	(5)
Sell Canadian dollar, buy U.S. dollar	CAD	**1,350**	1,250	**(28)**	6
Buy Canadian dollar, sell U.S. dollar	CAD	**13**	8	-	-
Sell British pound, buy Norwegian krone	GBP	-	9	-	-
Sell British pound, buy euro	GBP	-	12	-	-
Buy British pound, sell euro	GBP	**4**	-	-	-

**Denominated in USD, CAD and GBP.*
***Denominated in USD.*

For additional information about our use of derivative instruments, see Note 14—Derivative and Financial Instruments, in the Notes to Consolidated Financial Statements.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

INDEX TO 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 position, 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 management believes are reasonable under the circumstances. The company's financial statements have been audited by Ernst & Young LLP, an independent registered public accounting firm appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders. Management has made available to Ernst & Young LLP all of the company's financial records and related data, as well as the minutes of stockholders' and directors' meetings.

Assessment of Internal Control Over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. ConocoPhillips' internal control system was designed to provide reasonable assurance to the company's management and directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2019. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework (2013).* Based on our assessment, we believe the company's internal control over financial reporting was effective as of December 31, 2019.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2019, and their report is included herein.

/s/ Ryan M. Lance

Ryan M. Lance
Chairman and
Chief Executive Officer

/s/ Don E. Wallette, Jr.

Don E. Wallette, Jr.
Executive Vice President and
Chief Financial Officer

February 18, 2020

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of ConocoPhillips

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of ConocoPhillips (the Company) as of December 31, 2019 and 2018, the related consolidated income statement, consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2019, and the related notes, condensed consolidating financial information listed in the Index at Item 8, and financial statement schedule listed in Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 18, 2020, expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's 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 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 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 financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the Audit and Finance Committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for asset retirement obligations for certain offshore properties

Description of the Matter	At December 31, 2019, the asset retirement obligation ("ARO") balance totaled $6.2 billion. As further described in Note 10, the Company records AROs in the period in which they are incurred, typically when the asset is installed at the production location. The estimation of obligations related to certain offshore assets requires significant judgment given the magnitude of these removal costs and higher estimation uncertainty related to the removal plan and costs. Furthermore, given certain of these assets are nearing the end of their operations, the impact of changes in these AROs may result in a material impact to earnings given the relatively short remaining useful lives of the assets. Auditing the Company's AROs for the obligations identified above is complex and highly judgmental due to the significant estimation required by management in determining the obligations. In particular, the estimates were sensitive to significant subjective assumptions such as removal cost estimates and end of field life, which are affected by expectations about future market or economic conditions.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's internal controls over its ARO estimation process, including management's review of the significant assumptions that have a material effect on the determination of the obligations. We also tested management's controls over the completeness and accuracy of the financial data used in the valuation. To test the AROs for the obligations identified above, our audit procedures included, among others, assessing the significant assumptions and inputs used in the valuation, including removal cost estimates and end of field life assumptions. For example, we evaluated removal cost estimates by comparing to settlements and recent removal activities and costs. We also compared end of field life assumptions to production forecasts. We involved our internal specialists in testing the underlying removal cost estimates.

Depreciation, depletion and amortization of proved oil and gas properties

Description of the Matter	At December 31, 2019, the net book value of the Company's properties, plants and equipment was $42.3 billion, and depreciation, depletion and amortization (DD&A) expense was $6.1 billion for the year then ended. As described in Note 1, DD&A of properties, plants and equipment on producing hydrocarbon properties and certain pipeline and LNG assets (those which are expected to have a declining utilization pattern) are determined by the unit-of-production method based on proved oil and gas reserves, as estimated by the Company's internal reservoir engineers. Proved oil and gas reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and approved operating limits. Significant judgment is required by the Company's internal reservoir engineers in evaluating geological and engineering data when estimating proved oil and gas reserves. Estimating reserves also requires the selection of inputs, including oil and gas price assumptions, future operating and capital costs assumptions and tax rates by jurisdiction, among others. Because of the complexity involved in estimating oil and gas reserves, management also used a third-party petroleum engineering firm to perform a review of the processes and controls used by the Company's internal reservoir engineers to determine estimates of proved oil and gas reserves.

Auditing the Company's DD&A calculation is complex because of the use of the work of the internal reservoir engineers and third-party petroleum engineering firm and the evaluation of management's determination of the inputs described above used by the internal reservoir engineers in estimating proved oil and gas reserves.

How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's internal controls over its process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to the internal reservoir engineers for use in estimating proved oil and gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's internal reservoir engineers primarily responsible for overseeing the preparation of the reserve estimates and the third-party petroleum engineering firm used to review the Company's processes and controls. In addition, in assessing whether we can use the work of the internal reservoir engineers, we evaluated the completeness and accuracy of the financial data and inputs described above used by the internal reservoir engineers in estimating proved oil and gas reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company's drill plan. We also tested the accuracy of the DD&A calculations, including comparing the proved oil and gas reserve amounts used in the calculation to the Company's reserve report.

/s/ Ernst & Young LLP

We have served as ConocoPhillips' auditor since 1949.

Houston, Texas
February 18, 2020

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of ConocoPhillips

Opinion on Internal Control over Financial Reporting

We have audited ConocoPhillips' internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, ConocoPhillips (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

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, 2019 and 2018, the related consolidated income statement, consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2019, and the related notes, condensed consolidating financial information listed in the Index at Item 8, and financial statement schedule listed in Item 15(a) and our report dated February 18, 2020, expressed an unqualified opinion thereon.

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 under the heading "Assessment of Internal Control Over Financial Reporting" in the accompanying "Report of Management." 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 included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and 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/ Ernst & Young LLP

Houston, Texas
February 18, 2020

Consolidated Income Statement			**ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2019	2018	2017
Revenues and Other Income			
Sales and other operating revenues	$ **32,567**	36,417	29,106
Equity in earnings of affiliates	**779**	1,074	772
Gain on dispositions	**1,966**	1,063	2,177
Other income	**1,358**	173	529
Total Revenues and Other Income	**36,670**	38,727	32,584
Costs and Expenses			
Purchased commodities	**11,842**	14,294	12,475
Production and operating expenses	**5,322**	5,213	5,162
Selling, general and administrative expenses	**556**	401	427
Exploration expenses	**743**	369	934
Depreciation, depletion and amortization	**6,090**	5,956	6,845
Impairments	**405**	27	6,601
Taxes other than income taxes	**953**	1,048	809
Accretion on discounted liabilities	**326**	353	362
Interest and debt expense	**778**	735	1,098
Foreign currency transaction (gains) losses	**66**	(17)	35
Other expenses	**65**	375	451
Total Costs and Expenses	**27,146**	28,754	35,199
Income (loss) before income taxes	**9,524**	9,973	(2,615)
Income tax provision (benefit)	**2,267**	3,668	(1,822)
Net income (loss)	**7,257**	6,305	(793)
Less: net income attributable to noncontrolling interests	**(68)**	(48)	(62)
Net Income (Loss) Attributable to ConocoPhillips	$ **7,189**	6,257	(855)
Net Income (Loss) Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*			
Basic	$ **6.43**	5.36	(0.70)
Diluted	**6.40**	5.32	(0.70)
Average Common Shares Outstanding *(in thousands)*			
Basic	**1,117,260**	1,166,499	1,221,038
Diluted	**1,123,536**	1,175,538	1,221,038

See Notes to Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income				**ConocoPhillips**
Years Ended December 31		Millions of Dollars		
		2019	2018	2017
Net Income (Loss)	$	**7,257**	6,305	(793)
Other comprehensive income (loss)				
Defined benefit plans				
Prior service credit (cost) arising during the period		**-**	(7)	2
Reclassification adjustment for amortization of prior service credit included in net income (loss)		**(35)**	(40)	(38)
Net change		**(35)**	(47)	(36)
Net actuarial gain (loss) arising during the period		**(55)**	(150)	19
Reclassification adjustment for amortization of net actuarial losses included in net income (loss)		**146**	279	247
Net change		**91**	129	266
Nonsponsored plans*		**(3)**	(1)	(2)
Income taxes on defined benefit plans		**(2)**	(42)	(81)
Defined benefit plans, net of tax		**51**	39	147
Unrealized holding loss on securities		**-**	-	(58)
Unrealized loss on securities, net of tax		**-**	-	(58)
Foreign currency translation adjustments		**699**	(645)	586
Income taxes on foreign currency translation adjustments		**(4)**	3	-
Foreign currency translation adjustments, net of tax		**695**	(642)	586
Other Comprehensive Income (Loss), Net of Tax		**746**	(603)	675
Comprehensive Income (Loss)		**8,003**	5,702	(118)
Less: comprehensive income attributable to noncontrolling interests		**(68)**	(48)	(62)
Comprehensive Income (Loss) Attributable to ConocoPhillips	$	**7,935**	5,654	(180)

**Plans for which ConocoPhillips is not the primary obligor—primarily those administered by equity affiliates.*

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhillips**

At December 31		Millions of Dollars	
		2019	2018
Assets			
Cash and cash equivalents	$	**5,088**	5,915
Short-term investments		**3,028**	248
Accounts and notes receivable (net of allowance of $13 million in 2019 and $25 million in 2018)		**3,267**	3,920
Accounts and notes receivable—related parties		**134**	147
Investment in Cenovus Energy		**2,111**	1,462
Inventories		**1,026**	1,007
Prepaid expenses and other current assets		**2,259**	575
Total Current Assets		**16,913**	13,274
Investments and long-term receivables		**8,687**	9,329
Loans and advances—related parties		**219**	335
Net properties, plants and equipment (net of accumulated depreciation, depletion and amortization of $55,477 million in 2019 and $64,899 million in 2018)		**42,269**	45,698
Other assets		**2,426**	1,344
Total Assets	$	**70,514**	69,980
Liabilities			
Accounts payable	$	**3,176**	3,863
Accounts payable—related parties		**24**	32
Short-term debt		**105**	112
Accrued income and other taxes		**1,030**	1,320
Employee benefit obligations		**663**	809
Other accruals		**2,045**	1,259
Total Current Liabilities		**7,043**	7,395
Long-term debt		**14,790**	14,856
Asset retirement obligations and accrued environmental costs		**5,352**	7,688
Deferred income taxes		**4,634**	5,021
Employee benefit obligations		**1,781**	1,764
Other liabilities and deferred credits		**1,864**	1,192
Total Liabilities		**35,464**	37,916
Equity			
Common stock (2,500,000,000 shares authorized at $0.01 par value)			
Issued (2019—1,795,652,203 shares; 2018—1,791,637,434 shares)			
Par value		**18**	18
Capital in excess of par		**46,983**	46,879
Treasury stock (at cost: 2019—710,783,814 shares; 2018—653,288,213 shares)		**(46,405)**	(42,905)
Accumulated other comprehensive loss		**(5,357)**	(6,063)
Retained earnings		**39,742**	34,010
Total Common Stockholders' Equity		**34,981**	31,939
Noncontrolling interests		**69**	125
Total Equity		**35,050**	32,064
Total Liabilities and Equity	$	**70,514**	69,980

See Notes to Consolidated Financial Statements.

Years Ended December 31	Millions of Dollars		
	2019	2018	2017
Cash Flows From Operating Activities			
Net income (loss)	$ **7,257**	6,305	(793)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	**6,090**	5,956	6,845
Impairments	**405**	27	6,601
Dry hole costs and leasehold impairments	**421**	95	566
Accretion on discounted liabilities	**326**	353	362
Deferred taxes	**(444)**	283	(3,681)
Undistributed equity earnings	**594**	152	(232)
Gain on dispositions	**(1,966)**	(1,063)	(2,177)
Other	**(1,000)**	191	(429)
Working capital adjustments			
Decrease (increase) in accounts and notes receivable	**505**	235	(886)
Decrease (increase) in inventories	**(67)**	86	(55)
Decrease (increase) in prepaid expenses and other current assets	**37**	(55)	69
Increase (decrease) in accounts payable	**(378)**	(52)	265
Increase (decrease) in taxes and other accruals	**(676)**	421	622
Net Cash Provided by Operating Activities	**11,104**	12,934	7,077
Cash Flows From Investing Activities			
Capital expenditures and investments	**(6,636)**	(6,750)	(4,591)
Working capital changes associated with investing activities	**(103)**	(68)	132
Proceeds from asset dispositions	**3,012**	1,082	13,860
Net sales (purchases) of investments	**(2,910)**	1,620	(1,790)
Collection of advances/loans—related parties	**127**	119	115
Other	**(108)**	154	36
Net Cash Provided by (Used in) Investing Activities	**(6,618)**	(3,843)	7,762
Cash Flows From Financing Activities			
Repayment of debt	**(80)**	(4,995)	(7,876)
Issuance of company common stock	**(30)**	121	(63)
Repurchase of company common stock	**(3,500)**	(2,999)	(3,000)
Dividends paid	**(1,500)**	(1,363)	(1,305)
Other	**(119)**	(123)	(112)
Net Cash Used in Financing Activities	**(5,229)**	(9,359)	(12,356)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	**(46)**	(117)	232
Net Change in Cash, Cash Equivalents and Restricted Cash	**(789)**	(385)	2,715
Cash, cash equivalents and restricted cash at beginning of period	**6,151**	6,536	3,610
Cash, Cash Equivalents and Restricted Cash at End of Period	$ **5,362**	6,151	6,325

Restricted cash of $90 million and $184 million are included in the "Prepaid expenses and other current assets" and "Other assets" lines, respectively, of our Consolidated Balance Sheet as of December 31, 2019.
Restricted cash totaling $236 million is included in the "Other assets" line of our Consolidated Balance Sheet as of December 31, 2018.
See Notes to Consolidated Financial Statements.

Consolidated Statement of Changes in Equity

ConocoPhillips

	Millions of Dollars						
	Attributable to ConocoPhillips						
	Common Stock						
	Par Value	Capital in Excess of Par	Treasury Stock	Accum. Other Comprehensive Income (Loss)	Retained Earnings	Non-Controlling Interests	Total
December 31, 2016	$ 18	46,507	(36,906)	(6,193)	31,548	252	35,226
Net income (loss)					(855)	62	(793)
Other comprehensive income				675			675
Dividends paid ($1.06 per share of common stock)					(1,305)		(1,305)
Repurchase of company common stock			(3,000)				(3,000)
Distributions to noncontrolling interests and other						(120)	(120)
Distributed under benefit plans		115					115
Other					3		3
December 31, 2017	$ 18	46,622	(39,906)	(5,518)	29,391	194	30,801
Net income					6,257	48	6,305
Other comprehensive loss				(603)			(603)
Dividends paid ($1.16 per share of common stock)					(1,363)		(1,363)
Repurchase of company common stock			(2,999)				(2,999)
Distributions to noncontrolling interests and other						(121)	(121)
Distributed under benefit plans		257					257
Changes in Accounting Principles*				58	(278)		(220)
Other					3	4	7
December 31, 2018	$ 18	46,879	(42,905)	(6,063)	34,010	125	32,064
Net income					**7,189**	**68**	**7,257**
Other comprehensive income				**746**			**746**
Dividends paid ($1.34 per share of common stock)					**(1,500)**		**(1,500)**
Repurchase of company common stock			**(3,500)**				**(3,500)**
Distributions to noncontrolling interests and other						**(128)**	**(128)**
Distributed under benefit plans		**104**					**104**
Changes in Accounting Principles**				**(40)**	**40**		**-**
Other					**3**	**4**	**7**
December 31, 2019	**$ 18**	**46,983**	**(46,405)**	**(5,357)**	**39,742**	**69**	**35,050**

**Cumulative effect of the adoption of ASC Topic 606, "Revenue from Contracts with Customers," and ASU No. 2016-01, "Recognition and Measurement of Financial Assets and Liabilities," at January 1, 2018.*

***See Note 2—Changes in Accounting Principles for additional information.*

See Notes to Consolidated Financial Statements.

Note 1—Accounting Policies

- **Consolidation Principles and Investments**—Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we have the ability to exert significant influence over the affiliates' operating and financial policies. When we do not have the ability to exert significant influence, the investment is measured at fair value except when the investment does not have a readily determinable fair value. For those exceptions, it will be measured at cost minus impairment, plus or minus observable price changes in orderly transactions for an identical or similar investment of the same issuer. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants and terminals are consolidated on a proportionate basis. Other securities and investments are generally carried at cost.

  We manage our operations through six operating segments, defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International. For additional information, see Note 25—Segment Disclosures and Related Information.

- **Foreign Currency Translation**—Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in accumulated other comprehensive loss in common stockholders' equity. Foreign currency transaction gains and losses are included in current earnings. Some of our foreign operations use their local currency as the functional currency.

- **Use of Estimates**—The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from these estimates.

- **Revenue Recognition**—Revenues associated with the sales of crude oil, bitumen, natural gas, LNG, NGLs and other items are recognized at the point in time when the customer obtains control of the asset. In evaluating when a customer has control of the asset, we primarily consider whether the transfer of legal title and physical delivery has occurred, whether the customer has significant risks and rewards of ownership, and whether the customer has accepted delivery and a right to payment exists. These products are typically sold at prevailing market prices. We allocate variable market-based consideration to deliveries (performance obligations) in the current period as that consideration relates specifically to our efforts to transfer control of current period deliveries to the customer and represents the amount we expect to be entitled to in exchange for the related products. Payment is typically due within 30 days or less.

  Revenues associated with transactions commonly called buy/sell contracts, in which the purchase and sale of inventory with the same counterparty are entered into "in contemplation" of one another, are combined and reported net (i.e., on the same income statement line).

- **Shipping and Handling Costs**—We typically incur shipping and handling costs prior to control transferring to the customer and account for these activities as fulfillment costs. Accordingly, we include shipping and handling costs in production and operating expenses for production activities. Transportation costs related to marketing activities are recorded in purchased commodities. Freight costs billed to customers are treated as a component of the transaction price and recorded as a component of revenue when the customer obtains control.

- **Cash Equivalents**—Cash equivalents are highly liquid, short-term investments that are readily convertible to known amounts of cash and have original maturities of 90 days or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

- **Short-Term Investments**—Short-term investments include investments in bank time deposits and marketable securities (commercial paper and government obligations) which are carried at cost plus accrued interest and have original maturities of greater than 90 days but within one year or when the remaining maturities are within one year. We also invest in financial instruments classified as available for sale debt securities which are carried at fair value. Those instruments are included in short-term investments when they have remaining maturities within one year as of the balance sheet date.

- **Long-Term Investments in Debt Securities**—Long-term investments in debt securities includes financial instruments classified as available for sale debt securities with remaining maturities greater than one year as of the balance sheet date. They are carried at fair value and presented within the "Investments and long-term receivables" line of our consolidated balance sheet.

- **Inventories**—We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. The majority of our commodity-related inventories are recorded at cost using the LIFO basis. We measure these inventories at the lower-of-cost-or-market in the aggregate. Any necessary lower-of-cost-or-market write-downs at year end are recorded as permanent adjustments to the LIFO cost basis. LIFO is used to better match current inventory costs with current revenues. Costs include both direct and indirect expenditures incurred in bringing an item or product to its existing condition and location, but not unusual/nonrecurring costs or research and development costs. Materials, supplies and other miscellaneous inventories, such as tubular goods and well equipment, are valued using various methods, including the weighted-average-cost method, and the FIFO method, consistent with industry practice.

- **Fair Value Measurements**—Assets and liabilities measured at fair value and required to be categorized within the fair value hierarchy are categorized into one of three different levels depending on the observability of the inputs employed in the measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1 for the asset or liability, either directly or indirectly through market-corroborated inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or our assumptions about pricing by market participants.

- **Derivative Instruments**—Derivative instruments are recorded on the balance sheet at fair value. If the right of offset exists and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the balance sheet and the collateral payable or receivable is netted against derivative assets and derivative liabilities, respectively.

  Recognition and classification of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives not accounted for as hedges are recognized immediately in earnings.

- **Oil and Gas Exploration and Development**—Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

  Property Acquisition Costs—Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption PP&E. Leasehold impairment is recognized based on exploratory experience and management's judgment. Upon achievement of all conditions necessary for reserves to be classified as proved, the associated leasehold costs are reclassified to proved properties.

  Exploratory Costs—Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or "suspended," on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas resources are designated as proved reserves.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as dry holes when it judges the potential field does not warrant further investment in the near term. See Note 8—Suspended Wells and Other Exploration Expenses, for additional information on suspended wells.

Development Costs—Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Depletion and Amortization—Leasehold costs of producing properties are depleted using the unit-of-production method based on estimated proved oil and gas reserves. Amortization of intangible development costs is based on the unit-of-production method using estimated proved developed oil and gas reserves.

- **Capitalized Interest**—Interest from external borrowings is capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

- **Depreciation and Amortization**—Depreciation and amortization of PP&E on producing hydrocarbon properties and certain pipeline and LNG assets (those which are expected to have a declining utilization pattern), are determined by the unit-of-production method. Depreciation and amortization of all other PP&E are determined by either the individual-unit-straight-line method or the group-straight-line method (for those individual units that are highly integrated with other units).

- **Impairment of Properties, Plants and Equipment**—PP&E used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. If there is an indication the carrying amount of an asset may not be recovered, the asset is monitored by management through an established process where changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted before-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions and reported as impairments in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for E&P assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell, with fair value determined using a binding negotiated price, if available, or present value of expected future cash flows as previously described.

  The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, prices and costs, considering all available evidence at the date of review. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable and possible reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation.

- **Impairment of Investments in Nonconsolidated Entities**—Investments in nonconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred and annually following updates to corporate planning assumptions. When such a condition is judgmentally determined to be other than temporary, the carrying value of the investment is written down to fair value. The fair value of the impaired investment is based on quoted market prices, if available, or upon the present value of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

- **Maintenance and Repairs**—Costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

- **Property Dispositions**—When complete units of depreciable property are sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in the "Gain on dispositions" line of our consolidated income statement. When less than complete units of depreciable property are disposed of or retired which do not significantly alter the DD&A rate, the difference between asset cost and salvage value is charged or credited to accumulated depreciation.

- **Asset Retirement Obligations and Environmental Costs**—The fair value of legal obligations to retire and remove long-lived assets are recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time the liability is increased for the change in its present value, and the capitalized cost in PP&E is depreciated over the useful life of the related asset. Reductions to estimated liabilities for assets that are no longer producing are recorded as a credit to impairment, if the asset had been previously impaired, or as a credit to DD&A, if the asset had not been previously impaired. For additional information, see Note 10—Asset Retirement Obligations and Accrued Environmental Costs.

  Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures relating to an existing condition caused by past operations, and those having no future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination, which we record on a discounted basis) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is probable and estimable.

- **Guarantees**—The fair value of a guarantee is determined and recorded as a liability at the time the guarantee is given. The initial liability is subsequently reduced as we are released from exposure under the guarantee. We amortize the guarantee liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of guarantee. In cases where the guarantee term is indefinite, we reverse the liability when we have information indicating the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related income statement line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

- **Share-Based Compensation**—We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award) or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. We have elected to recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

- **Income Taxes**—Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial reporting basis and the tax basis of our assets and liabilities, except for deferred taxes on income and temporary differences related to the cumulative translation adjustment considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures. Allowable tax credits are applied currently as reductions of the provision for income taxes. Interest related to unrecognized tax benefits is reflected in interest and debt expense, and penalties related to unrecognized tax benefits are reflected in production and operating expenses.

- **Taxes Collected from Customers and Remitted to Governmental Authorities**—Sales and value-added taxes are recorded net.

- **Net Income (Loss) Per Share of Common Stock**—Basic net income (loss) per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year. Also, this calculation includes fully vested stock and unit awards that have not yet been issued as common stock, along with an adjustment to net income (loss) for dividend equivalents paid on unvested unit awards that are considered participating securities. Diluted net income per share of common stock includes unvested stock, unit or option awards granted under our compensation plans and vested but unexercised stock options, but only to the extent these instruments dilute net income per share, primarily under the treasury-stock method. Diluted net loss per share, which is calculated the same as basic net loss per share, does not assume conversion or exercise of securities that would have an antidilutive effect. Treasury stock is excluded from the daily weighted-average number of common shares outstanding in both calculations. The earnings per share impact of the participating securities is immaterial.

Note 2—Changes in Accounting Principles

We adopted the provisions of FASB ASU No. 2016-02, "Leases," (ASC Topic 842) and its amendments, beginning January 1, 2019. ASC Topic 842 establishes comprehensive accounting and financial reporting requirements for leasing arrangements, supersedes the existing requirements in FASB ASC Topic 840, "Leases" (ASC Topic 840), and requires lessees to recognize substantially all lease assets and lease liabilities on the balance sheet. The provisions of ASC Topic 842 also modify the definition of a lease and outline requirements for recognition, measurement, presentation and disclosure of leasing arrangements by both lessees and lessors.

We adopted ASC Topic 842 using the modified retrospective approach and elected to utilize the Optional Transition Method, which permits us to apply the provisions of ASC Topic 842 to leasing arrangements existing at or entered into after January 1, 2019, and present in our financial statements comparative periods prior to January 1, 2019 under the historical requirements of ASC Topic 840. In addition, we elected to adopt the package of optional transition-related practical expedients, which among other things, allows us to carry forward certain historical conclusions reached under ASC Topic 840 regarding lease identification, classification, and the accounting treatment of initial direct costs. Furthermore, we elected not to record assets and liabilities on our consolidated balance sheet for new or existing lease arrangements with terms of 12 months or less.

The primary impact of applying ASC Topic 842 is the initial recognition of $998 million of lease liabilities and corresponding right-of-use assets on our consolidated balance sheet as of January 1, 2019, for leases classified as operating leases under ASC Topic 840, as well as enhanced disclosure of our leasing arrangements. Our accounting treatment for finance leases remains unchanged. In addition, there is no cumulative effect to retained earnings or other components of equity recognized as of January 1, 2019, and the adoption of ASC Topic 842 did not impact the presentation of our consolidated income statement or statement of cash flows. See Note 17—Non-Mineral Leases for additional information related to the adoption of ASC Topic 842.

We adopted the provisions of FASB ASU No. 2018-02, “Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income,” beginning January 1, 2019. The ASU allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act, eliminating the stranded tax effects. The cumulative effect to our consolidated balance sheet at January 1, 2019 for the adoption of ASU No. 2018-02 was as follows:

		Millions of Dollars		
		December 31 2018	ASU No. 2018-02 Adjustments	**January 1 2019**
Equity				
Accumulated other comprehensive loss	$	(6,063)	(40)	**(6,103)**
Retained earnings		34,010	40	**34,050**

For additional information regarding the impact of the adoption of ASU No. 2018-02, see Note 20—Accumulated Other Comprehensive Loss.

Note 3—Variable Interest Entities

We hold variable interests in VIEs for which there are existing arrangements that provide those entities with additional forms of subordinated financial support. However, as we are not considered the primary beneficiary, these entities have not been consolidated in our financial statements.

Marine Well Containment Company, LLC (MWCC)
We have a 10 percent ownership interest in MWCC, and it is accounted for as an equity method investment because MWCC is a limited liability company in which we are a founding member. MWCC is considered a VIE, as it has entered into arrangements that provide it with additional forms of subordinated financial support. We are not the primary beneficiary and do not consolidate MWCC because we share the power to govern the business and operation of the company and to undertake certain obligations that most significantly impact its economic performance with nine other unaffiliated owners of MWCC.

Based on inputs related to the fair value of MWCC observed in the second quarter of 2019, we reduced the carrying value of our equity method investment in MWCC to $30 million and recorded a before-tax impairment of $95 million which is included in the “Equity in earnings of affiliates” line on our consolidated income statement. For additional information see Note 15—Fair Value Measurement. At December 31, 2019, the book value of our equity method investment in MWCC was $24 million. We have not provided any financial support to MWCC other than amounts previously contractually required. Unless we elect otherwise, we have no requirement to provide liquidity or purchase the assets of MWCC.

Australia Pacific LNG Pty Ltd (APLNG)
We hold a 37.5 percent interest in APLNG, our joint venture with Origin Energy and Sinopec. We are not the primary beneficiary because we share, with our joint venture partners, the power to direct the key activities of APLNG that most significantly impacts its economic performance. Therefore, we do not consolidate APLNG and account for this entity as an equity method investment. As of December 31, 2019, we no longer have certain guarantees that provide APLNG with additional subordinated financial support. For additional information see Note 12—Guarantees.

Note 4—Inventories

Inventories at December 31 were:

		Millions of Dollars	
		2019	2018
Crude oil and natural gas	$	**472**	432
Materials and supplies		**554**	575
	$	**1,026**	1,007

Inventories valued on the LIFO basis totaled $286 million and $292 million at December 31, 2019 and 2018, respectively. The estimated excess of current replacement cost over LIFO cost of inventories was approximately $155 million and $75 million at December 31, 2019 and December 31, 2018, respectively.

Note 5—Asset Acquisitions and Dispositions

All gains or losses on asset dispositions are reported before-tax and are included net in the "Gain on dispositions" line on our consolidated income statement. All cash proceeds are included in the "Cash Flows From Investing Activities" section of our consolidated statement of cash flows.

2019

Assets Held for Sale

In October 2019, we entered into an agreement to sell the subsidiaries that hold our Australia-West assets and operations to Santos for $1.39 billion, plus customary adjustments, with an effective date of January 1, 2019. In addition, we will receive a payment of $75 million upon final investment decision of the Barossa development project. These subsidiaries hold our 37.5 percent interest in the Barossa Project and Caldita Field, our 56.9 percent interest in the Darwin LNG Facility and Bayu-Undan Field, our 40 percent interest in the Greater Poseidon Fields, and our 50 percent interest in the Athena Field. The net carrying value is approximately $0.6 billion, which consisted primarily of $1.2 billion of PP&E and $0.3 billion of cash and working capital, offset by $0.7 billion of ARO and $0.2 billion of deferred tax liabilities. The assets met held for sale criteria in the fourth quarter, and as of December 31, 2019 we had reclassified $1.2 billion of PP&E to "Prepaid expenses and other current assets" and $0.7 billion of noncurrent ARO to "Other accruals" on our consolidated balance sheet. The before-tax earnings associated with our Australia-West subsidiaries were $372 million, $364 million and $317 million for the years ended December 31, 2019, 2018 and 2017, respectively. This transaction is expected to be completed in the first quarter of 2020, subject to regulatory approvals and other specific conditions precedent. Results of operations for the subsidiaries to be sold are reported within our Asia Pacific and Middle East segment.

In the fourth quarter of 2019, we signed an agreement to sell our interests in the Niobrara shale play for $380 million, plus customary adjustments, and overriding royalty interests in certain future wells. To reduce the carrying value to fair value, in the fourth quarter of 2019, we recorded an impairment of $379 million before-tax for developed properties and exploration expenses of $7 million related to leasehold impairment of undeveloped properties. Our Niobrara interests to be sold have a net carrying value of approximately $390 million, which consisted primarily of $426 million of PP&E, offset by $34 million of noncurrent ARO. The assets met held for sale criteria in the fourth quarter, and as of December 31, 2019, we had reclassified $426 million of PP&E to "Prepaid expenses and other current assets" and $34 million of noncurrent AROs to "Other accruals" on our consolidated balance sheet. The before-tax losses associated with our interests in Niobrara, including the $386 million of impairments noted above, were $372 million and $12 million for the years ended December 31, 2019 and 2017, respectively. The before-tax earnings associated with our interests in Niobrara for the year ended December 31, 2018 was $35 million. This transaction is subject to regulatory approval and other specific conditions precedent and is expected to close in the first quarter of 2020. The Niobrara results of operations are reported within our Lower 48 segment.

Assets Sold
In January 2019, we entered into agreements to sell our 12.4 percent ownership interests in the Golden Pass LNG Terminal and Golden Pass Pipeline. We also entered into agreements to amend our contractual obligations for retaining use of the facilities. As a result of entering into these agreements, we recorded a before-tax impairment of $60 million in the first quarter of 2019 which is included in the "Equity in earnings of affiliates" line on our consolidated income statement. We completed the sale in the second quarter of 2019. Results of operations for these assets are reported in our Lower 48 segment. See Note 15—Fair Value Measurement for additional information.

In April 2019, we entered into an agreement to sell two ConocoPhillips U.K. subsidiaries to Chrysaor E&P Limited for $2.675 billion plus interest and customary adjustments, with an effective date of January 1, 2018. On September 30, 2019, we completed the sale for proceeds of $2.2 billion and recognized a $1.7 billion before-tax and $2.1 billion after-tax gain associated with this transaction in 2019. Together the subsidiaries sold indirectly held our exploration and production assets in the U.K. At the time of disposition, the net carrying value was approximately $0.5 billion, consisting primarily of $1.6 billion of PP&E, $0.5 billion of cumulative foreign currency translation adjustments, and $0.3 billion of deferred tax assets, offset by $1.8 billion of ARO and negative $0.1 billion of working capital. The before-tax earnings associated with the subsidiaries sold were $0.4 billion, $0.9 billion and $0.3 billion for the years ended December 31, 2019, 2018 and 2017, respectively. Results of operations for the U.K. are reported within our Europe and North Africa segment.

In the second quarter of 2019, we recognized an after-tax gain of $52 million upon the closing of the sale of our 30 percent interest in the Greater Sunrise Fields to the government of Timor-Leste for $350 million. The Greater Sunrise Fields were included in our Asia Pacific and Middle East segment.

In the fourth quarter of 2019, we sold our interests in the Magnolia field and platform for net proceeds of $16 million and recognized a before-tax gain of $82 million. At the time of sale, the net carrying value consisted of $4 million of PP&E offset by $70 million of ARO. The Magnolia results of operations are reported within our Lower 48 segment.

Planned Dispositions
In January 2020, we entered into an agreement to sell our interests in certain non-core properties in the Lower 48 segment for $186 million, plus customary adjustments. The assets met the held for sale criteria in January 2020 and the transaction is expected to be completed in the first quarter of 2020. No gain or loss is anticipated on the sale. This disposition will not have a significant impact on Lower 48 production.

2018
Assets Sold
In the first quarter of 2018, we completed the sale of certain properties in the Lower 48 segment for net proceeds of $112 million. No gain or loss was recognized on the sale. In the second quarter of 2018, we completed the sale of a package of largely undeveloped acreage in the Lower 48 segment for net proceeds of $105 million and no gain or loss was recognized on the sale. In the third quarter of 2018, we completed a noncash exchange of undeveloped acreage in the Lower 48 segment. The transaction was recorded at fair value resulting in the recognition of a $56 million gain. In the fourth quarter of 2018, we sold several packages of undeveloped acreage in the Lower 48 segment for total net proceeds of $162 million and recognized gains of approximately $140 million.

On October 31, 2018, we completed the sale of our interests in the Barnett to Lime Rock Resources for $196 million after customary adjustments and recognized a loss of $5 million. We recorded impairments of $87 million in 2018 and $572 million in 2017 to reduce the net carrying value of the Barnett to fair value. At the time of the disposition, our interest in Barnett had a net carrying value of $201 million, consisting of $250 million of PP&E and $49 million of AROs. The before-tax losses associated with our interests in the Barnett, including both the impairments and loss on disposition noted above, were $59 million and $566 million for the years 2018 and 2017, respectively. The Barnett results of operations are included in our Lower 48 segment.

On December 18, 2018, we completed the sale of a ConocoPhillips subsidiary to BP. The subsidiary held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the U.K. We retained a 7.5 percent interest in the field. At the same time, we acquired BP's 39.2 percent nonoperated interest in the Greater Kuparuk Area in Alaska, including their 38 percent interest in the Kuparuk Transportation Company (Kuparuk Assets). The transaction was recorded at a fair value of $1,743 million and was cash neutral except for customary adjustments which resulted in net proceeds of $253 million. At closing, our interest in the Clair Field had a net carrying value of approximately $1,028 million consisting primarily of $1,553 million of PP&E, $485 million of deferred tax liabilities, and $59 million of AROs. We recognized a before-tax gain of $715 million on the transaction. The 2018 before-tax earnings associated with our 16.5 interest in the Clair Field, including the recognized gain, were $748 million. The before-tax loss associated with our interest in the Clair Field was $0.4 million for 2017. Results of operations for our interest in the Clair Field are reported within our Europe and North Africa segment and the Kuparuk Assets are included in our Alaska segment.

Acquisitions
In May 2018, we completed the acquisition of Anadarko's 22 percent nonoperated interest in the Western North Slope of Alaska, as well as its interest in the Alpine Transportation Pipeline for $386 million, after customary adjustments. This transaction was accounted for as a business combination resulting in the recognition of approximately $297 million of proved property and $114 million of unproved property within PP&E, $20 million of inventory, $14 million of investments, and $59 million of AROs. These assets are included in our Alaska segment.

As discussed in the Clair Field transaction with BP above, we acquired BP's Kuparuk Assets on December 18, 2018. The transaction was accounted for as an asset acquisition with a net acquisition cost of $1,490 million, comprised of the fair value of $1,743 million associated with the disposed 16.5 percent of our 24 percent interest in the Clair Field, reduced by the net proceeds of $253 million. Accordingly, we recorded approximately $1.9 billion to proved property within PP&E, $42 million to inventory, $15 million to investments, $374 million of AROs, and a $100 million decrease to net working capital. The Kuparuk Assets are included in our Alaska segment.

2017
Assets Sold
On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the Foster Creek Christina Lake (FCCL) Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Consideration for the transaction was $11.0 billion in cash after customary adjustments, 208 million Cenovus Energy common shares and a five-year uncapped contingent payment. The value of the shares at closing was $1.96 billion based on a price of $9.41 per share on the NYSE. The contingent payment, calculated and paid on a quarterly basis, is $6 million CAD for every $1 CAD by which the WCS quarterly average crude price exceeds $52 CAD per barrel. Contingent payments received during the five-year period are reflected as "Gain on dispositions" on our consolidated income statement. We reported before-tax equity earnings associated with FCCL of $197 million for 2017. We reported a before-tax loss of $26 million for the western Canada gas producing properties for 2017. We recorded gains on dispositions for these contingent payments of $114 million and $95 million for the years 2019 and 2018, respectively.

At closing, the carrying value of our equity investment in FCCL was $8.9 billion. The carrying value of our interest in the western Canada gas assets was $1.9 billion consisting primarily of $2.6 billion of PP&E, partly offset by AROs of $585 million and approximately $100 million of environmental and other accruals. A gain of $2.1 billion was included in the "Gain on dispositions" line on our consolidated income statement in 2017. Both FCCL and the western Canada gas assets were reported in our Canada segment.

For more information on the Canada disposition and our investment in Cenovus Energy see Note 7—Investment in Cenovus Energy, Note 15—Fair Value Measurement, and Note 20—Accumulated Other Comprehensive Loss.

In July 2017, we completed the sale of our interests in the San Juan Basin to an affiliate of Hilcorp Energy

Company for $2.5 billion in cash after customary adjustments and recognized a loss on disposition of $22 million. The transaction includes a contingent payment of up to $300 million. The six-year contingent payment, effective beginning January 1, 2018, is due annually for the periods in which the monthly U.S. Henry Hub price is at or above $3.20 per MMBTU. In 2018, we recorded a gain on dispositions for these contingent payments of $28 million. No contingent payments were recorded in 2019. In the second quarter of 2017, we recorded an impairment of $3.3 billion to reduce the carrying value of our interests in the San Juan Basin to fair value. At the time of disposition, the San Juan Basin interests had a net carrying value of approximately $2.5 billion, consisting of $2.9 billion of PP&E and $406 million of liabilities, primarily AROs. The before-tax loss associated with our interests in the San Juan Basin, including both the $3.3 billion impairment and $22 million loss on disposition noted above, was $3.2 billion for 2017. The San Juan Basin results were reported in our Lower 48 segment.

In September 2017, we completed the sale of our interest in the Panhandle assets for $178 million in cash after customary adjustments and recognized a loss on disposition of $28 million. At the time of the disposition, the carrying value of our interest was $206 million, consisting primarily of $279 million of PP&E and $72 million of AROs. Including the $28 million loss on disposition noted above, we reported a before-tax loss for the Panhandle properties of $14 million for 2017. The Panhandle results were reported in our Lower 48 segment.

Note 6—Investments, Loans and Long-Term Receivables

Components of investments, loans and long-term receivables at December 31 were:

		Millions of Dollars	
		2019	2018
Equity investments	$	**8,234**	9,005
Loans and advances—related parties		**219**	335
Long-term receivables		**243**	238
Long-term investments in debt securities		**133**	-
Other investments		**77**	86
	$	**8,906**	9,664

Equity Investments

Affiliated companies in which we had a significant equity investment at December 31, 2019, included:

- APLNG—37.5 percent owned joint venture with Origin Energy (37.5 percent) and Sinopec (25 percent)—to produce CBM from the Bowen and Surat basins in Queensland, Australia, as well as process and export LNG.
- Qatar Liquefied Gas Company Limited (3) (QG3)—30 percent owned joint venture with affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent)—produces and liquefies natural gas from Qatar's North Field, as well as exports LNG.

Summarized 100 percent earnings information for equity method investments in affiliated companies, combined, was as follows:

		Millions of Dollars		
		2019	2018	2017
Revenues	$	**11,310**	11,654	11,554
Income (loss) before income taxes		**3,726**	3,660	(2,875)
Net income (loss)		**3,085**	3,244	(1,431)

Summarized 100 percent balance sheet information for equity method investments in affiliated companies, combined, was as follows:

		Millions of Dollars	
		2019	2018
Current assets	$	**3,289**	3,285
Noncurrent assets		**38,905**	41,563
Current liabilities		**2,603**	2,625
Noncurrent liabilities		**22,168**	23,874

Our share of income taxes incurred directly by an equity method investee is reported in equity in earnings of affiliates, and as such is not included in income taxes on our consolidated financial statements.

At December 31, 2019, retained earnings included $32 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $1,378 million, $1,226 million and $605 million in 2019, 2018 and 2017, respectively.

APLNG

APLNG is focused on CBM production from the Bowen and Surat basins in Queensland, Australia, to supply the domestic gas market and on LNG processing and export sales. Our investment in APLNG gives us access to CBM resources in Australia and enhances our LNG position. The majority of APLNG LNG is sold under two long-term sales and purchase agreements, supplemented with sales of additional LNG spot cargoes targeting the Asia Pacific markets. Origin Energy, an integrated Australian energy company, is the operator of APLNG's production and pipeline system, while we operate the LNG facility.

APLNG executed project financing agreements for an $8.5 billion project finance facility in 2012. The $8.5 billion project finance facility was initially composed of financing agreements executed by APLNG with the Export-Import Bank of the United States for approximately $2.9 billion, the Export-Import Bank of China for approximately $2.7 billion, and a syndicate of Australian and international commercial banks for approximately $2.9 billion. At December 31, 2019, all amounts have been drawn from the facility. APLNG made its first principal and interest repayment in March 2017 and is scheduled to make bi-annual payments until March 2029.

APLNG made a voluntary repayment of $1.4 billion to the Export-Import Bank of China in September 2018. At the same time, APLNG obtained a United States Private Placement (USPP) bond facility of $1.4 billion. APLNG made its first interest payment related to this facility in March 2019, and principal payments are scheduled to commence in September 2023, with bi-annual payments due on the facility until September 2030.

During the first quarter of 2019, APLNG refinanced $3.2 billion of existing project finance debt through two transactions. As a result of the first transaction, APLNG obtained a commercial bank facility of $2.6 billion. APLNG made its first principal and interest repayment in September 2019 with bi-annual payments due on the facility until March 2028. Through the second transaction, APLNG obtained a USPP bond facility of $0.6 billion. APLNG made its first interest payment in September 2019, and principal payments are scheduled to commence in September 2023, with bi-annual payments due on the facility until September 2030.

In conjunction with the $3.2 billion debt obtained during the first quarter of 2019 to refinance existing project finance debt, APLNG made voluntary repayments of $2.2 billion and $1.0 billion to a syndicate of Australian and international commercial banks and the Export-Import Bank of China, respectively.

At December 31, 2019, a balance of $6.7 billion was outstanding on the facilities. See Note 12—Guarantees, for additional information.

During the first half of 2017, the outlook for crude oil prices deteriorated, and as a result of significantly reduced price outlooks, the estimated fair value of our investment in APLNG declined to an amount below carrying value. Based on a review of the facts and circumstances surrounding this decline in fair value, we concluded in the second quarter of 2017 the impairment was other than temporary under the guidance of FASB ASC Topic 323, "Investments—Equity Method and Joint Ventures," and the recognition of an impairment of our investment to fair value was necessary. Accordingly, we recorded a noncash $2,384 million, before- and after-tax impairment in our second quarter 2017 results. Fair value was estimated based on an internal discounted cash flow model using estimated future production, an outlook of future prices from a combination of exchanges (short-term) and pricing service companies (long-term), costs, a market outlook of foreign exchange rates provided by a third party, and a discount rate believed to be consistent with those used by principal market participants. The impairment was included in the "Impairments" line on our consolidated income statement.

At December 31, 2019, the carrying value of our equity method investment in APLNG was $7,228 million. The historical cost basis of our 37.5 percent share of net assets on the books of APLNG was $6,751 million, resulting in a basis difference of $477 million on our books. The basis difference, which is substantially all associated with PP&E and subject to amortization, has been allocated on a relative fair value basis to individual exploration and production license areas owned by APLNG, some of which are not currently in production. Any future additional payments are expected to be allocated in a similar manner. Each exploration license area will periodically be reviewed for any indicators of potential impairment, which, if required, would result in acceleration of basis difference amortization. As the joint venture produces natural gas from each license, we amortize the basis difference allocated to that license using the unit-of-production method. Included in net income (loss) attributable to ConocoPhillips for 2019, 2018 and 2017 was after-tax expense of $36 million, $44 million and $100 million, respectively, representing the amortization of this basis difference on currently producing licenses.

Distributions from APLNG commenced in April 2018.

FCCL

FCCL Partnership, a Canadian upstream 50/50 general partnership with Cenovus Energy Inc., produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend. Cenovus is the operator and managing partner of FCCL.

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets to Cenovus Energy. Financial information presented within this footnote includes our historical interest up to the date of sale. For additional information on the Canada disposition and our investment in Cenovus Energy, see Note 5—Asset Acquisitions and Dispositions and Note 7—Investment in Cenovus Energy.

QG3

QG3 is a joint venture that owns an integrated large-scale LNG project located in Qatar. We provided project financing, with a current outstanding balance of $335 million as described below under "Loans and Long-Term Receivables." At December 31, 2019, the book value of our equity method investment in QG3, excluding the project financing, was $797 million. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. We previously held a 12.4 percent interest in Golden Pass LNG Terminal and Golden Pass Pipeline, but we sold those interests in the second quarter of 2019 while retaining the basic use agreements. Currently, the LNG from QG3 is being sold to markets outside of the U.S. For additional information, see Note 5—Asset Acquisitions and Dispositions.

Loans and Long-Term Receivables
As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans and long-term receivables to certain affiliated and non-affiliated companies. Loans are recorded when cash is transferred or seller financing is provided to the affiliated or non-affiliated company pursuant to a loan agreement. The loan balance will increase as interest is earned on the outstanding loan balance and will decrease as interest and principal payments are received. Interest is earned at the loan agreement's stated interest rate. Loans and long-term receivables are assessed for impairment when events indicate the loan balance may not be fully recovered.

At December 31, 2019, significant loans to affiliated companies include $335 million in project financing to QG3. We own a 30 percent interest in QG3, for which we use the equity method of accounting. The other participants in the project are affiliates of Qatar Petroleum and Mitsui. QG3 secured project financing of $4.0 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. On December 15, 2011, QG3 achieved financial completion and all project loan facilities became nonrecourse to the project participants. Semi-annual repayments began in January 2011 and will extend through July 2022.

The long-term portion of these loans is included in the "Loans and advances—related parties" line on our consolidated balance sheet, while the short-term portion is in "Accounts and notes receivable—related parties."

Note 7—Investment in Cenovus Energy

On May 17, 2017, we completed the sale of our 50 percent nonoperated interest in the FCCL Partnership, as well as the majority of our western Canada gas assets, to Cenovus Energy. Consideration for the transaction included 208 million Cenovus Energy common shares, which, at closing, approximated 16.9 percent of issued and outstanding Cenovus Energy common stock. See Note 5—Asset Acquisitions and Dispositions, for additional information on the Canada disposition. The fair value and cost basis of our investment in 208 million Cenovus Energy common shares was $1.96 billion based on a price of $9.41 per share on the NYSE on the closing date.

Our investment on our consolidated balance sheet as of December 31, 2019, is carried at fair value of $2.11 billion, reflecting the closing price of Cenovus Energy shares on the NYSE of $10.15 per share, an increase of $649 million from $1.46 billion at December 31, 2018. The increase in fair value represents the net unrealized gain recorded within the "Other income" line of our consolidated income statement for the year ended December 31, 2019 relating to the shares held at the reporting date. See Note 15—Fair Value Measurement and Note 22—Other Financial Information, for additional information. Subject to market conditions, we intend to decrease our investment over time through market transactions, private agreements or otherwise.

Note 8—Suspended Wells and Other Exploration Expenses

The following table reflects the net changes in suspended exploratory well costs during 2019, 2018 and 2017:

		Millions of Dollars		
		2019	2018	2017
Beginning balance at January 1	$	**856**	853	1,063
Additions pending the determination of proved reserves		**239**	140	118
Reclassifications to proved properties		**(11)**	(37)	(66)
Sales of suspended wells		**(54)**	(93)	-
Charged to dry hole expense		**(10)**	(7)	(262)
Ending balance at December 31	$	**1,020 ***	856	853

**Includes $313 million of assets held for sale in Australia.*

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

		Millions of Dollars		
		2019	2018	2017
Exploratory well costs capitalized for a period of one year or less	$	**206**	145	67
Exploratory well costs capitalized for a period greater than one year		**814**	711	786
Ending balance	$	**1,020 ***	856	853
Number of projects with exploratory well costs capitalized for a period greater than one year		**23**	24	23

**Includes $313 million of assets held for sale in Australia.*

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2019:

		Millions of Dollars			
			Suspended Since		
		Total	2016–2018	2013–2015	2004–2012
Greater Poseidon—Australia(2)(3)		177	-	157	20
NPRA—Alaska(1)		149	111	38	-
Barossa/Caldita—Australia(2)(3)		136	59	-	77
Surmont—Canada(1)		118	6	55	57
Middle Magdalena Basin—Colombia(1)		68	-	68	-
Narwhal Trend—Alaska(1)		52	52	-	-
Kamunsu East—Malaysia(2)		19	-	19	-
NC 98—Libya(2)		15	-	11	4
WL4-00—Malaysia(2)		17	17	-	-
Other of $10 million or less each(1)(2)		63	20	26	17
Total	$	814	265	374	175

(1)Additional appraisal wells planned.
(2)Appraisal drilling complete; costs being incurred to assess development.
(3)Assets held for sale as of December 31, 2019.

Other Exploration Expenses

In February 2017, we reached a settlement agreement on our contract for the Athena drilling rig, initially secured for our four-well commitment program in Angola. As a result of the cancellation, we recognized a before-tax charge of $43 million net in the first quarter of 2017. These charges are included in the "Exploration expenses" line on our consolidated income statement and in our Other International segment in 2017.

In 2019, we recorded before-tax dry hole expenses of $111 million due to our decision to discontinue exploration activities in the Central Louisiana Austin Chalk trend. These charges are included in our Lower 48 segment and in the "Exploration expenses" line on our consolidated income statement. See Note 9—Impairments for additional information on our decision to discontinue these exploration activities.

Note 9—Impairments

During 2019, 2018 and 2017, we recognized the following before-tax impairment charges:

		Millions of Dollars		
		2019	2018	2017
Alaska	$	-	20	180
Lower 48		**402**	63	3,969
Canada		**2**	9	22
Europe and North Africa		**1**	(79)	46
Asia Pacific and Middle East		-	14	2,384
	$	**405**	27	6,601

2019

In the Lower 48, we recorded impairments of $402 million, primarily related to developed properties in our Niobrara asset which were written down to fair value less costs to sell. See Note 5—Asset Acquisitions and Dispositions, for additional information on this disposition.

The charges discussed below, within this section, are included in the "Exploration expenses" line on our consolidated income statement and are not reflected in the table above.

In our Lower 48 segment, we recorded a before-tax impairment of $141 million for the associated carrying value of capitalized undeveloped leasehold costs due to our decision to discontinue exploration activities related to our Central Louisiana Austin Chalk acreage.

2018

In Alaska, we recorded impairments of $20 million primarily due to cancelled projects.

In the Lower 48, we recorded impairments of $63 million, primarily related to developed properties in our Barnett asset which were written down to fair value less costs to sell, partly offset by a revision to reflect finalized proceeds on a separate transaction.

In our Europe and North Africa segment, we recorded a credit to impairment of $79 million, primarily due to decreased ARO estimates on fields in the U.K. which have ceased production and were impaired in prior years, partly offset by an increased ARO estimate on a field in Norway which has ceased production.

2017
In Alaska, we recorded impairments of $180 million primarily for the associated PP&E carrying value of our small interest in the Point Thomson unit.

In the Lower 48, we recorded impairments of $3,969 million primarily due to certain developed properties which were written down to fair value less costs to sell. See Note 5—Asset Acquisitions and Dispositions, for additional information on our dispositions.

In Canada, we recorded impairments of $22 million primarily due to cancelled projects.

In Europe and North Africa, we recorded impairments of $46 million primarily due to reduced volume forecasts for a field in the U.K. and restructured ownership and a change in commercial premises for a gas processing plant in Norway, partly offset by decreased ARO estimates on fields at or nearing the end of life which were impaired in prior years.

In Asia Pacific and Middle East, we recorded impairments of $2,384 million, including the impairment of our APLNG investment. For more information, see the "APLNG" section of Note 6—Investments, Loans and Long-Term Receivables.

The charges discussed below, within this section, are included in the "Exploration expenses" line on our consolidated income statement and are not reflected in the table above.

In our Lower 48 segment, we recorded a before-tax impairment of $51 million for the associated carrying value of capitalized undeveloped leasehold costs of Shenandoah in deepwater Gulf of Mexico following the suspension of appraisal activity by the operator. Additionally, we recorded a $38 million before-tax impairment for mineral assets primarily due to plan of development changes.

Note 10—Asset Retirement Obligations and Accrued Environmental Costs

Asset retirement obligations and accrued environmental costs at December 31 were:

	Millions of Dollars	
	2019	2018
Asset retirement obligations	$ **6,206**	7,908
Accrued environmental costs	**171**	178
Total asset retirement obligations and accrued environmental costs	**6,377**	8,086
Asset retirement obligations and accrued environmental costs due within one year*	**(1,025)**	(398)
Long-term asset retirement obligations and accrued environmental costs	$ **5,352**	7,688

**Classified as a current liability on the balance sheet under "Other accruals." $741 million relates to assets which are held for sale as of December 31, 2019. For additional information see Note 5—Asset Acquisitions and Dispositions.*

Asset Retirement Obligations

We record the fair value of a liability for an ARO when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize the associated asset retirement cost by increasing the carrying amount of the related PP&E. If, in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset.

We have numerous AROs we are required to perform under law or contract once an asset is permanently taken out of service. Most of these obligations are not expected to be paid until several years, or decades, in the future and will be funded from general company resources at the time of removal. Our largest individual obligations involve plugging and abandonment of wells and removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska.

During 2019 and 2018, our overall ARO changed as follows:

	Millions of Dollars	
	2019	2018
Balance at January 1	$ **7,908**	7,798
Accretion of discount	**322**	348
New obligations	**155**	657
Changes in estimates of existing obligations	**50**	(266)
Spending on existing obligations	**(229)**	(228)
Property dispositions	**(1,920)**	(161)
Foreign currency translation	**(80)**	(240)
Balance at December 31	$ **6,206**	7,908

Accrued Environmental Costs
Total accrued environmental costs at December 31, 2019 and 2018, were $171 million and $178 million, respectively.

We had accrued environmental costs of $112 million and $100 million at December 31, 2019 and 2018, respectively, related to remediation activities in the U.S. and Canada. We had also accrued in Corporate and Other $47 million and $67 million of environmental costs associated with sites no longer in operation at December 31, 2019 and 2018, respectively. In addition, $12 million and $11 million were included at both December 31, 2019 and 2018, respectively, where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, or similar state laws. Accrued environmental liabilities are expected to be paid over periods extending up to 30 years.

Expected expenditures for environmental obligations acquired in various business combinations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $97 million at December 31, 2019. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $10 million in 2020, $7 million in 2021, $10 million in 2022, $3 million in 2023, $2 million in 2024, and $108 million for all future years after 2024.

Note 11—Debt

Long-term debt at December 31 was:

		Millions of Dollars	
		2019	2018
9.125% Debentures due 2021	$	**123**	123
8.20% Debentures due 2025		**134**	134
8.125% Notes due 2030		**390**	390
7.9% Debentures due 2047		**60**	60
7.8% Debentures due 2027		**203**	203
7.65% Debentures due 2023		**78**	78
7.40% Notes due 2031		**500**	500
7.375% Debentures due 2029		**92**	92
7.25% Notes due 2031		**500**	500
7.20% Notes due 2031		**575**	575
7% Debentures due 2029		**200**	200
6.95% Notes due 2029		**1,549**	1,549
6.875% Debentures due 2026		**67**	67
6.50% Notes due 2039		**2,750**	2,750
5.951% Notes due 2037		**645**	645
5.95% Notes due 2036		**500**	500
5.95% Notes due 2046		**500**	500
5.90% Notes due 2032		**505**	505
5.90% Notes due 2038		**600**	600
4.95% Notes due 2026		**1,250**	1,250
4.30% Notes due 2044		**750**	750
4.15% Notes due 2034		**246**	246
3.35% Notes due 2024		**426**	426
3.35% Notes due 2025		**199**	199
2.4% Notes due 2022		**329**	329
Floating rate notes due 2022 at 2.81% – 3.58% during 2019 and 2.32% – 3.52% during 2018		**500**	500
Industrial Development Bonds due 2035 at 1.08% – 2.45% during 2019 and 0.95% – 1.86% during 2018		**18**	18
Marine Terminal Revenue Refunding Bonds due 2031 at 1.08% – 2.45% during 2019 and 0.88% – 1.95% during 2018		**265**	265
Other		**17**	17
Debt at face value		**13,971**	13,971
Finance leases		**720**	777
Net unamortized premiums, discounts and debt issuance costs		**204**	220
Total debt		**14,895**	14,968
Short-term debt		**(105)**	(112)
Long-term debt	$	**14,790**	14,856

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2020 through 2024 are: $105 million, $235 million, $940 million, $198 million and $548 million, respectively.

We have a revolving credit facility totaling $6.0 billion with an expiration date of May 2023. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper program. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the U.S. The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

We have a $6.0 billion commercial paper program, which is primarily a funding source for short-term working capital needs. Commercial paper maturities are generally limited to 90 days. We had no commercial paper outstanding in programs in place at December 31, 2019 or December 31, 2018. We had no direct outstanding borrowings or letters of credit under the revolving credit facility at December 31, 2019 or December 31, 2018. Since we had no commercial paper outstanding and had issued no letters of credit, we had access to $6.0 billion in borrowing capacity under our revolving credit facility at December 31, 2019.

At both December 31, 2019 and 2018, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding which mature in 2035. The VRDBs are redeemable at the option of the bondholders on any business day. If they are ever redeemed, we intend to refinance on a long-term basis, therefore, the VRDBs are included in the "Long-term debt" line on our consolidated balance sheet.

For additional information on Finance Leases, see Note 17—Non-Mineral Leases.

Note 12—Guarantees

At December 31, 2019, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability because the fair value of the obligation is immaterial. In addition, unless otherwise stated, we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

APLNG Guarantees
At December 31, 2019, we had outstanding multiple guarantees in connection with our 37.5 percent ownership interest in APLNG. The following is a description of the guarantees with values calculated utilizing December 2019 exchange rates:

- During the third quarter of 2016, we issued a guarantee to facilitate the withdrawal of our pro-rata portion of the funds in a project finance reserve account. We estimate the remaining term of this guarantee is 11 years. Our maximum exposure under this guarantee is approximately $170 million and may become payable if an enforcement action is commenced by the project finance lenders against APLNG. At December 31, 2019, the carrying value of this guarantee is approximately $14 million.

- In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to reimburse Origin Energy for our share of the existing contingent liability arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of up to 22 years. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $780 million ($1.4 billion in the event of intentional or reckless breach) and would become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG.

- We have guaranteed the performance of APLNG with regard to certain other contracts executed in connection with the project's continued development. The guarantees have remaining terms of up to 26 years or the life of the venture. As of December 31, 2019, we were released from certain of these guarantees considered subordinated financial support to APLNG. Our remaining maximum potential amount of future payments related to the remaining guarantees is approximately $60 million and would become payable if APLNG does not perform.

Other Guarantees

We have other guarantees with maximum future potential payment amounts totaling approximately $820 million, which consist primarily of guarantees of the residual value of leased office buildings, guarantees of the residual value of leased corporate aircraft, and a guarantee for our portion of a joint venture's project finance reserve accounts. These guarantees have remaining terms of up to three years and would become payable if, upon sale, certain asset values are lower than guaranteed amounts, business conditions decline at guaranteed entities, or as a result of nonperformance of contractual terms by guaranteed parties.

In conjunction with the disposition of our two U.K. subsidiaries to Chrysaor E&P Limited, we will temporarily continue to support various guarantees and letters of credit which were provided for the benefit of entities that are now affiliates of Chrysaor E&P Limited. Our maximum potential payment exposure under these obligations is approximately $100 million. Chrysaor E&P Limited has agreed to fully indemnify ConocoPhillips for any losses suffered by us related to these obligations.

Indemnifications

Over the years, we have entered into agreements to sell ownership interests in certain corporations, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes, environmental liabilities, employee claims and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2019, was approximately $80 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the recorded carrying amount at December 31, 2019, were approximately $30 million of environmental accruals for known contamination that are included in the "Asset retirement obligations and accrued environmental costs" line on our consolidated balance sheet. For additional information about environmental liabilities, see Note 13—Contingencies and Commitments.

Note 13—Contingencies and Commitments

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. With respect to income tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. See Note 19—Income Taxes, for additional information about income tax-related contingencies.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

Environmental

We are subject to international, federal, state and local environmental laws and regulations. When we prepare our consolidated financial statements, we record accruals for environmental liabilities based on management's best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into account stakeholder and business considerations. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies' cleanup experience, and data released by the U.S. EPA or other organizations. We consider unasserted claims in our determination of environmental liabilities, and we accrue them in the period they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for other sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all cleanup costs related to any site at which we have been designated as a potentially responsible party. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the agency concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability, and we adjust our accruals accordingly. As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit, and some of the indemnifications are subject to dollar limits and time limits.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state and international sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 10—Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

Legal Proceedings
We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, climate change, personal injury, and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties and claims of alleged environmental contamination from historic operations. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

Other Contingencies
We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2019, we had performance obligations secured by letters of credit of $277 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

In 2007, ConocoPhillips was unable to reach agreement with respect to the empresa mixta structure mandated by the Venezuelan government's Nationalization Decree. As a result, Venezuela's national oil company, Petróleos de Venezuela, S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips' interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, ConocoPhillips initiated international arbitration on November 2, 2007, with the ICSID. On September 3, 2013, an ICSID arbitration tribunal held that Venezuela unlawfully expropriated ConocoPhillips' significant oil investments in June 2007. On January 17, 2017, the Tribunal reconfirmed the decision that the expropriation was unlawful. In March 2019, the Tribunal unanimously ordered the government of Venezuela to pay ConocoPhillips approximately $8.7 billion in compensation for the government's unlawful expropriation of the company's investments in Venezuela in 2007. ConocoPhillips has filed a request for recognition of the award in several jurisdictions. On August 29, 2019, the ICSID Tribunal issued a decision rectifying the award and reducing it by approximately $227 million. The award now stands at $8.5 billion plus interest. The government of Venezuela sought annulment of the award.

In 2014, ConocoPhillips filed a separate and independent arbitration under the rules of the ICC against PDVSA under the contracts that had established the Petrozuata and Hamaca projects. The ICC Tribunal issued an award in April 2018, finding that PDVSA owed ConocoPhillips approximately $2 billion under their agreements in connection with the expropriation of the projects and other pre-expropriation fiscal measures. In August 2018, ConocoPhillips entered into a settlement with PDVSA to recover the full amount of this ICC award, plus interest through the payment period, including initial payments totaling approximately $500 million within a period of 90 days from the time of signing of the settlement agreement. The balance of the settlement is to be paid quarterly over a period of four and a half years. To date, ConocoPhillips has received approximately $754 million. Per the settlement, PDVSA recognized the ICC award as a judgment in various jurisdictions, and ConocoPhillips agreed to suspend its legal enforcement actions. ConocoPhillips sent notices of default to PDVSA on October 14 and November 12, 2019, and to date PDVSA failed to cure its breach. As a result, ConocoPhillips has resumed legal enforcement actions. ConocoPhillips has ensured that the settlement and any actions thereof meet all appropriate U.S. regulatory requirements, including those related to any applicable sanctions imposed by the U.S. against Venezuela.

In 2016, ConocoPhillips filed a separate and independent arbitration under the rules of the ICC against PDVSA under the contracts that had established the Corocoro project. On August 2, 2019, the ICC Tribunal awarded ConocoPhillips approximately $55 million under the Corocoro contracts. ConocoPhillips is seeking recognition and enforcement of the award in various jurisdictions. ConocoPhillips has ensured that all the actions related to the award meet all appropriate U.S. regulatory requirements, including those related to any applicable sanctions imposed by the U.S. against Venezuela.

In February 2017, the ICSID Tribunal unanimously awarded Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, $380 million for Ecuador's unlawful expropriation of Burlington's investment in Blocks 7 and 21, in breach of the U.S.-Ecuador Bilateral Investment Treaty. The tribunal also issued a separate decision finding Ecuador to be entitled to $42 million for environmental and infrastructure counterclaims. In December 2017, Burlington and Ecuador entered into a settlement agreement by which Ecuador paid Burlington $337 million in two installments. The first installment of $75 million was paid in December 2017, and the second installment of $262 million was paid in April 2018. The settlement included an offset for the counterclaims decision, of which Burlington is entitled to a contribution from Perenco Ecuador Limited, its co-venturer and consortium operator, pursuant to a joint and several liability provision in the JOA. In September 2019, a separate ICSID Tribunal issued an award in the Perenco arbitration, ordering Perenco to pay an additional $54 million to Ecuador for its environmental counterclaim. Burlington and Perenco will reconcile their shares of the environmental and infrastructure counterclaims according to their JOA participating interests, and we expect Burlington's share will be immaterial.

In June 2017, FAR Ltd. initiated arbitration before the ICC against ConocoPhillips Senegal B.V. in connection with the sale of ConocoPhillips Senegal B.V. to Woodside Energy Holdings (Senegal) Limited in 2016. In February 2020, the ICC Tribunal issued an award dismissing FAR Ltd.'s claims in the arbitration.

In late 2017, ConocoPhillips (U.K.) Limited (CPUKL) initiated United Nations Commission on International Trade and Law (UNCITRAL) arbitration against Vietnam in accordance with the U.K.-Vietnam Bilateral Investment Treaty relating to a tax dispute arising from the 2012 sale of ConocoPhillips (U.K.) Cuu Long Limited and ConocoPhillips (U.K.) Gama Limited. The parties entered into a settlement agreement in October 2019, and the arbitration was dismissed in December 2019 as a result of this agreement.

In 2017 and 2018, cities, counties, and a state government in California, New York, Washington, Rhode Island and Maryland, as well as the Pacific Coast Federation of Fishermen's Association, Inc., have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. ConocoPhillips is vigorously defending against these lawsuits. The lawsuits brought by the Cities of San Francisco, Oakland and New York have been dismissed by the district courts and appeals are pending. Lawsuits filed by other cities and counties in California and Washington are currently stayed pending resolution of the appeals brought by the Cities of San Francisco and Oakland to the U.S. Court of Appeals for the Ninth Circuit. Lawsuits filed in Maryland and Rhode Island are proceeding in state court while rulings in those matters, on the issue of whether the matters should proceed in state or federal court, are on appeal to the U.S. Court of Appeals for the Fourth Circuit and First Circuit, respectively.

Several Louisiana parishes and individual landowners have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages in connection with historical oil and gas operations in Louisiana. All parish lawsuits are stayed pending an appeal to the Fifth Circuit Court of Appeals on the issue of whether they will proceed in federal or state court. ConocoPhillips will vigorously defend against these lawsuits.

Long-Term Throughput Agreements and Take-or-Pay Agreements
We have certain throughput agreements and take-or-pay agreements in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company's business. The aggregate amounts of estimated payments under these various agreements are: 2020—$7 million; 2021—$7 million; 2022—$7 million; 2023—$7 million; 2024—$7 million; and 2025 and after—$57 million. Total payments under the agreements were $25 million in 2019, $39 million in 2018 and $43 million in 2017.

Note 14—Derivative and Financial Instruments

We use futures, forwards, swaps and options in various markets to meet our customer needs and capture market opportunities. Our commodity business primarily consists of natural gas, crude oil, bitumen, LNG and NGLs.

Our derivative instruments are held at fair value on our consolidated balance sheet. Where these balances have the right of setoff, they are presented on a net basis. Related cash flows are recorded as operating activities on our consolidated statement of cash flows. On our consolidated income statement, realized and unrealized gains and losses are recognized either on a gross basis if directly related to our physical business or a net basis if held for trading. Gains and losses related to contracts that meet and are designated with the NPNS exception are recognized upon settlement. We generally apply this exception to eligible crude contracts. We do not use hedge accounting for our commodity derivatives.

The following table presents the gross fair values of our commodity derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

		Millions of Dollars	
		2019	2018
Assets			
Prepaid expenses and other current assets	$	**288**	410
Other assets		**34**	40
Liabilities			
Other accruals		**283**	370
Other liabilities and deferred credits		**28**	30

The gains (losses) from commodity derivatives incurred, and the line items where they appear on our consolidated income statement were:

		Millions of Dollars		
		2019	2018	2017
Sales and other operating revenues	$	**141**	45	77
Other income		**4**	7	-
Purchased commodities		**(118)**	(41)	(61)

The table below summarizes our material net exposures resulting from outstanding commodity derivative contracts:

	Open Position Long/(Short)	
	2019	2018
Commodity		
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(5)**	(17)
Basis	**(23)**	(1)

Foreign Currency Exchange Derivatives
We have foreign currency exchange rate risk resulting from international operations. Our foreign currency exchange derivative activity primarily relates to managing our cash-related foreign currency exchange rate exposures, such as firm commitments for capital programs or local currency tax payments, dividends and cash returns from net investments in foreign affiliates, and investments in equity securities. We do not elect hedge accounting on our foreign currency exchange derivatives.

The following table presents the gross fair values of our foreign currency exchange derivatives, excluding collateral, and the line items where they appear on our consolidated balance sheet:

	Millions of Dollars	
	2019	2018
Assets		
Prepaid expenses and other current assets	**$ 1**	7
Liabilities		
Other accruals	**20**	6
Other liabilities and deferred credits	**8**	-

The losses from foreign currency exchange derivatives incurred and the line item where they appear on our consolidated income statement were:

	Millions of Dollars		
	2019	2018	2017
Foreign currency transaction losses	**$ 16**	1	13

We had the following net notional position of outstanding foreign currency exchange derivatives:

		In Millions Notional Currency	
		2019	2018
Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy British pound	USD	-	805
Sell British pound, buy other currencies*	GBP	-	21
Buy British pound, sell euro	GBP	**4**	-
Sell Canadian dollar, buy U.S. dollar	CAD	**1,337**	1,242

**Primarily euro and Norwegian krone.*

In December 2017, we entered into foreign exchange zero cost collars buying the right to sell $1.25 billion CAD at $0.707 CAD and selling the right to buy $1.25 billion CAD at $0.842 CAD against the U.S. dollar. The collar expired during the second quarter of 2019 and we entered into new foreign currency exchange forward contracts to sell $1.35 billion CAD at $0.748 CAD against the U.S. dollar.

Financial Instruments

We invest in financial instruments with maturities based on our cash forecasts for the various accounts and currency pools we manage. The types of financial instruments in which we currently invest include:

- Time deposits: Interest bearing deposits placed with financial institutions.
- Demand deposits: Interest bearing deposits placed with financial institutions. Deposited funds can be withdrawn without notice.
- Commercial paper: Unsecured promissory notes issued by a corporation, commercial bank or government agency purchased at a discount to mature at par.
- U.S. government or government agency obligations: Securities issued by the U.S. government or U.S. government agencies.
- Corporate bonds: Unsecured debt securities issued by corporations.
- Asset-backed securities: Collateralized debt securities.

The following investments are carried on our consolidated balance sheet at cost, plus accrued interest:

	Carrying Amount			
	Cash and Cash Equivalents		Short-Term Investments	
	2019	2018	**2019**	2018
Cash	$ **759**	876		
Demand Deposits	**1,483**	-	-	-
Time Deposits				
Remaining maturities from 1 to 90 days	**2,030**	3,509	**1,395**	-
Remaining maturities from 91 to 180 days	-	-	**465**	-
Commercial Paper				
Remaining maturities from 1 to 90 days	**413**	229	**1,069**	248
U.S. Government Obligations				
Remaining maturities from 1 to 90 days	**394**	1,301	-	-
	$ **5,079**	5,915	**2,929**	248

The following table reflects our investments in debt securities classified as available for sale at December 31, 2019 which are carried at fair value:

	Millions of Dollars		
	Carrying Amount		
	Cash and Cash Equivalents	Short-Term Investments	Investments and Long-Term Receivables
Corporate Bonds			
Remaining maturities within one year	$ **1**	**59**	**-**
Remaining maturities greater than one year through five years	**-**	**-**	**99**
Commercial Paper			
Remaining maturities within one year	**8**	**30**	**-**
U.S. Government Obligations			
Remaining maturities within one year	**-**	**10**	**-**
Remaining maturities greater than one year through five years	**-**	**-**	**15**
Asset-backed Securities			
Remaining maturities greater than one year through five years	**-**	**-**	**19**
	$ **9**	**99**	**133**

The following table summarizes the amortized cost basis and fair value of investments in debt securities classified as available for sale at December 31, 2019:

	Millions of Dollars	
	Amortized Cost Basis	Fair Value
Major Security Type		
Corporate bonds	$ **159**	**159**
Commercial paper	**38**	**38**
U.S. government obligations	**25**	**25**
Asset-backed securities	**19**	**19**
	$ **241**	**241**

Gross unrealized gains and gross unrealized losses included in other comprehensive income related to investments in debt securities classified as available for sale as of December 31, 2019, were negligible. There were no other-than-temporary impairments recognized in earnings or in other comprehensive income during the year ended December 31, 2019.

Gross realized gains and gross realized losses included in earnings from sales and redemptions of investments in debt securities classified as available for sale during the year ended December 31, 2019, were negligible. The cost of securities sold and redeemed is determined using the specific identification method.

Credit Risk
Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, short-term investments, long-term investments in debt securities, OTC derivative contracts and trade receivables. Our cash equivalents and short-term investments are placed in high-quality commercial paper, government money market funds, government debt securities, time deposits with major international banks and financial institutions, and high-quality corporate bonds. Our long-term investments in debt securities are placed in high-quality corporate bonds, U.S. government obligations, and asset-backed securities.

The credit risk from our OTC derivative contracts, such as forwards, swaps and options, derives from the counterparty to the transaction. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures, swaps and option contracts that have a negligible credit risk because these trades are cleared primarily with an exchange clearinghouse and subject to mandatory margin requirements until settled; however, we are exposed to the credit risk of those exchange brokers for receivables arising from daily margin cash calls, as well as for cash deposited to meet initial margin requirements.

Our trade receivables result primarily from our petroleum operations and reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor this exposure and the creditworthiness of the counterparties. We do not generally require collateral to limit the exposure to loss; however, we will sometimes use letters of credit, prepayments and master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owed by us or owed to others to be offset against amounts due to us.

Certain of our derivative instruments contain provisions that require us to post collateral if the derivative exposure exceeds a threshold amount. We have contracts with fixed threshold amounts and other contracts with variable threshold amounts that are contingent on our credit rating. The variable threshold amounts typically decline for lower credit ratings, while both the variable and fixed threshold amounts typically revert to zero if we fall below investment grade. Cash is the primary collateral in all contracts; however, many also permit us to post letters of credit as collateral, such as transactions administered through the New York Mercantile Exchange.

The aggregate fair value of all derivative instruments with such credit risk-related contingent features that were in a liability position on December 31, 2019 and December 31, 2018, was $79 million and $62 million, respectively. For these instruments, no collateral was posted as of December 31, 2019 or December 31, 2018. If our credit rating had been downgraded below investment grade on December 31, 2019, we would be required to post $76 million of additional collateral, either with cash or letters of credit.

Note 15—Fair Value Measurement

We carry a portion of our assets and liabilities at fair value that are measured at a reporting date using an exit price (i.e., the price that would be received to sell an asset or paid to transfer a liability) and disclosed according to the quality of valuation inputs under the following hierarchy:

- Level 1: Quoted prices (unadjusted) in an active market for identical assets or liabilities.
- Level 2: Inputs other than quoted prices that are directly or indirectly observable.
- Level 3: Unobservable inputs that are significant to the fair value of assets or liabilities.

The classification of an asset or liability is based on the lowest level of input significant to its fair value. Those that are initially classified as Level 3 are subsequently reported as Level 2 when the fair value derived from unobservable inputs is inconsequential to the overall fair value, or if corroborated market data becomes available. Assets and liabilities initially reported as Level 2 are subsequently reported as Level 3 if corroborated market data is no longer available. Transfers occur at the end of the reporting period. There were no material transfers in or out of Level 1 during 2019 or 2018.

Recurring Fair Value Measurement
Financial assets and liabilities reported at fair value on a recurring basis primarily include our investment in Cenovus Energy shares, our investments in debt securities classified as available for sale, and commodity derivatives.

- Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. Level 1 also includes our investment in common shares of Cenovus Energy, which is valued using quotes for shares on the NYSE, and our investments in U.S. government obligations classified as available for sale debt securities, which are valued using exchange prices.
- Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. Level 2 also includes our investments in debt securities classified as available for sale including investments in corporate bonds, commercial paper, and asset-backed securities that are valued using pricing provided by brokers or pricing service companies that are corroborated with market data.
- Level 3 derivative assets and liabilities consist of OTC swaps, options and forward purchase and sale contracts where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived value uses industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management's best estimate of fair value. Level 3 activity was not material for all periods presented.

The following table summarizes the fair value hierarchy for gross financial assets and liabilities (i.e., unadjusted where the right of setoff exists for commodity derivatives accounted for at fair value on a recurring basis):

	Millions of Dollars							
	December 31, 2019				December 31, 2018			
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets								
Investment in Cenovus Energy	**$ 2,111**	**-**	**-**	**2,111**	1,462	-	-	1,462
Investments in debt securities	**25**	**216**	**-**	**241**				
Commodity derivatives	**172**	**114**	**36**	**322**	236	181	33	450
Total assets	**$ 2,308**	**330**	**36**	**2,674**	1,698	181	33	1,912
Liabilities								
Commodity derivatives	**$ 174**	**115**	**22**	**311**	225	145	30	400
Total liabilities	**$ 174**	**115**	**22**	**311**	225	145	30	400

The following table summarizes those commodity derivative balances subject to the right of setoff as presented on our consolidated balance sheet. We have elected to offset the recognized fair value amounts for multiple derivative instruments executed with the same counterparty in our financial statements when a legal right of setoff exists.

		Millions of Dollars						
				Amounts Subject to Right of Setoff				
		Gross Amounts Recognized	Amounts Not Subject to Right of Setoff	Gross Amounts	Gross Amounts Offset	Net Amounts Presented	Cash Collateral	Net Amounts
December 31, 2019								
Assets	**$**	**322**	**3**	**319**	**193**	**126**	**4**	**122**
Liabilities		**311**	**4**	**307**	**193**	**114**	**12**	**102**
December 31, 2018								
Assets	$	450	9	441	280	161	-	161
Liabilities		400	4	396	280	116	10	106

At December 31, 2019 and December 31, 2018, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

Non-Recurring Fair Value Measurement

The following table summarizes the fair value hierarchy by major category and date of remeasurement for assets accounted for at fair value on a non-recurring basis:

		Millions of Dollars				
			Fair Value Measurements Using			
		Fair Value	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs	Before-Tax Loss
Year ended December 31, 2019						
Net PP&E (held for sale)						
November 30, 2019	**$**	**194**	**194**	-	-	**351**
December 31, 2019		**166**	**166**	-	-	**28**
Equity Method Investments						
March 31, 2019		**171**	**171**	-	-	**60**
May 31, 2019		**30**	-	**30**	-	**95**
Year ended December 31, 2018						
Net PP&E (held for sale)						
March 31, 2018	$	250	-	-	250	44
September 30, 2018		201	201	-	-	43

Net PP&E (held for sale)
Net PP&E held for sale was written down to fair value, less costs to sell. The fair value of each asset was determined by its negotiated selling price (Level 1) or information gathered during marketing efforts (Level 3). For additional information see Note 5—Asset Acquisitions and Dispositions.

Equity Method Investments
During 2019, certain equity method investments were determined to have fair values below their carrying amounts, and the impairments were considered to be other than temporary under the guidance of FASB ASC Topic 323. During 2019, investments using Level 1 inputs were written down to fair value, less costs to sell,

determined by negotiated selling prices. For additional information, see Note 5—Asset Acquisitions and Dispositions. During 2019, an investment using Level 2 inputs was determined to have a fair value below its carrying value, and was written down to fair value. For additional information, see Note 3—Variable Interest Entities.

Reported Fair Values of Financial Instruments
We used the following methods and assumptions to estimate the fair value of financial instruments:

- Cash and cash equivalents and short-term investments: The carrying amount reported on the balance sheet approximates fair value. For those investments classified as available for sale debt securities, the carrying amount reported on the balance sheet is fair value.
- Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value. The valuation technique and methods used to estimate the fair value of the current portion of fixed-rate related party loans is consistent with Loans and advances—related parties.
- Investment in Cenovus Energy shares: See Note 7—Investment in Cenovus Energy for a discussion of the carrying value and fair value of our investment in Cenovus Energy shares.
- Investments in debt securities classified as available for sale: The fair value of investments in debt securities categorized as Level 1 in the fair value hierarchy is measured using exchange prices. The fair value of investments in debt securities categorized as Level 2 in the fair value hierarchy is measured using pricing provided by brokers or pricing service companies that are corroborated with market data. See Note 14—Derivatives and Financial Instruments, for additional information.
- Loans and advances—related parties: The carrying amount of floating-rate loans approximates fair value. The fair value of fixed-rate loan activity is measured using market observable data and is categorized as Level 2 in the fair value hierarchy. See Note 6—Investments, Loans and Long-Term Receivables, for additional information.
- Accounts payable (including related parties) and floating-rate debt: The carrying amount of accounts payable and floating-rate debt reported on the balance sheet approximates fair value.
- Fixed-rate debt: The estimated fair value of fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data; therefore, these liabilities are categorized as Level 2 in the fair value hierarchy.

The following table summarizes the net fair value of financial instruments (i.e., adjusted where the right of setoff exists for commodity derivatives):

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2019	2018	**2019**	2018
Financial assets				
Investment in Cenovus Energy	$ **2,111**	1,462	**2,111**	1,462
Commodity derivatives	**125**	170	**125**	170
Investments in debt securities	**241**	-	**241**	-
Total loans and advances—related parties	**339**	468	**339**	468
Financial liabilities				
Total debt, excluding finance leases	**14,175**	14,191	**18,108**	16,147
Commodity derivatives	**106**	110	**106**	110

Commodity Derivatives
At December 31, 2019, commodity derivative assets and liabilities are presented net with $4 million in obligations to return cash collateral and $12 million of rights to reclaim cash collateral, respectively. At December 31, 2018, commodity derivative assets and liabilities are presented net with no obligations to return cash collateral and $10 million of rights to reclaim cash collateral, respectively.

Note 16—Equity

Common Stock
The changes in our shares of common stock, as categorized in the equity section of the balance sheet, were:

	Shares		
	2019	2018	2017
Issued			
Beginning of year	**1,791,637,434**	1,785,419,175	1,782,079,107
Distributed under benefit plans	**4,014,769**	6,218,259	3,340,068
End of year	**1,795,652,203**	1,791,637,434	1,785,419,175
Held in Treasury			
Beginning of year	**653,288,213**	608,312,034	544,809,771
Repurchase of common stock	**57,495,601**	44,976,179	63,502,263
End of year	**710,783,814**	653,288,213	608,312,034

Preferred Stock
We have authorized 500 million shares of preferred stock, par value $0.01 per share, none of which was issued or outstanding at December 31, 2019 or 2018.

Noncontrolling Interests
At December 31, 2019 and 2018, we had $69 million and $125 million outstanding, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. For both periods, the amounts were related to the Darwin LNG and Bayu-Darwin Pipeline operating joint ventures we control.

Repurchase of Common Stock
As of December 31, 2019, we had announced a total authorization to repurchase $15 billion of our common stock. Repurchase of shares began in November 2016, and totaled 168,553,141 shares at a cost of $9,625 million, through December 31, 2019. In February 2020, we announced that the Board of Directors approved an increase to our repurchase authorization from $15 billion to $25 billion, to support our plan for future share repurchases.

Note 17—Non-Mineral Leases

The company primarily leases office buildings and drilling equipment, as well as ocean transport vessels, tugboats, corporate aircraft, and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices and other leases include payment provisions that vary based on the nature of usage of the leased asset. Additionally, the company has executed certain leases that provide it with the option to extend or renew the term of the lease, terminate the lease prior to the end of the lease term, or purchase the leased asset as of the end of the lease term. In other cases, the company has executed lease agreements that require it to guarantee the residual value of certain leased office buildings. For additional information about guarantees, see Note 12—Guarantees. There are no significant restrictions imposed on us by the lease agreements with regard to dividends, asset dispositions or borrowing ability.

Certain arrangements may contain both lease and non-lease components and we determine if an arrangement is or contains a lease at contract inception. Only the lease components of these contractual arrangements are subject to the provisions of ASC Topic 842, and any non-lease components are subject to other applicable accounting guidance; however, we have elected to adopt the optional practical expedient not to separate lease components apart from non-lease components for accounting purposes. This policy election has been adopted for each of the company's leased asset classes existing as of the effective date and subject to the transition provisions of ASC Topic 842 and will be applied to all new or modified leases executed on or after January 1, 2019. For contractual arrangements executed in subsequent periods involving a new leased asset class, the company will determine at contract inception whether it will apply the optional practical expedient to the new leased asset class.

Leases are evaluated for classification as operating or finance leases at the commencement date of the lease and right-of-use assets and corresponding liabilities are recognized on our consolidated balance sheet based on the present value of future lease payments relating to the use of the underlying asset during the lease term. Future lease payments include variable lease payments that depend upon an index or rate using the index or rate at the commencement date and probable amounts owed under residual value guarantees. The amount of future lease payments may be increased to include additional payments related to lease extension, termination, and/or purchase options when the company has determined, at or subsequent to lease commencement, generally due to limited asset availability or operating commitments, it is reasonably certain of exercising such options. We use our incremental borrowing rate as the discount rate in determining the present value of future lease payments, unless the interest rate implicit in the lease arrangement is readily determinable. Lease payments that vary subsequent to the commencement date based on future usage levels, the nature of leased asset activities, or certain other contingencies are not included in the measurement of lease right-of-use assets and corresponding liabilities. We have elected not to record assets and liabilities on our consolidated balance sheet for lease arrangements with terms of 12 months or less.

We often enter into leasing arrangements acting in the capacity as operator for and/or on behalf of certain oil and gas joint ventures of undivided interests. If the lease arrangement can be legally enforced only against us as operator and there is no separate arrangement to sublease the underlying leased asset to our coventurers, we recognize at lease commencement a right-of-use asset and corresponding lease liability on our consolidated balance sheet on a gross basis. While we record lease costs on a gross basis in our consolidated income statement and statement of cash flows, such costs are offset by the reimbursement we receive from our coventurers for their share of the lease cost as the underlying leased asset is utilized in joint venture activities. As a result, lease cost is presented in our consolidated income statement and statement of cash flows on a proportional basis. If we are a nonoperating coventurer, we recognize a right-of-use asset and corresponding lease liability only if we were a specified contractual party to the lease arrangement and the arrangement could be legally enforced against us. In this circumstance, we would recognize both the right-of-use asset and corresponding lease liability on our consolidated balance sheet on a proportional basis consistent with our undivided interest ownership in the related joint venture.

The company has historically recorded certain finance leases executed by investee companies accounted for under the proportionate consolidation method of accounting on its consolidated balance sheet on a proportional basis consistent with its ownership interest in the investee company. In addition, the company has historically recorded finance lease assets and liabilities associated with certain oil and gas joint ventures on a proportional basis pursuant to accounting guidance applicable prior to January 1, 2019. As of December 31, 2018, $420 million of finance lease assets (net of accumulated DD&A) and $688 million of finance lease liabilities were recorded on our consolidated balance sheet associated with these leases. In accordance with the transition provisions of ASC Topic 842, and since we have elected to adopt the package of optional transition-related practical expedients, the historical accounting treatment for these leases has been carried forward and is subject to reconsideration upon the modification or other required reassessment of the arrangements prior to lease term expiration.

In connection with our adoption of ASC Topic 842, we have recorded on our consolidated balance sheet $57 million of operating leases executed by investee companies accounted for under the proportionate consolidation method of accounting on a proportional basis consistent with our ownership interest in the investee company.

The following tables summarize the finance leases amounts that were reflected on our consolidated balance sheet as of December 31, 2018, the operating leases impact of adopting ASC Topic 842, and the right-of-use asset and lease liability balances reflected for both operating and finance leases on our consolidated balance sheet as of December 31, 2019:

	Millions of Dollars	
	Carrying Amount	
	Operating Leases	Finance Leases
Amounts recognized in line items in our Consolidated Balance Sheet upon adoption of ASC Topic 842		
Right-of-Use Assets		
Properties, plants and equipment		
Gross		$ 1,044
Accumulated depreciation, depletion and amortization		(550)
Net properties, plants and equipment as of December 31, 2018		$ 494
Adoption of ASC Topic 842 as of January 1, 2019	$ 998	
Lease Liabilities		
Short-term debt		$ 79
Long-term debt		698
Total finance leases debt as of December 31, 2018		$ 777
Adoption of ASC Topic 842 as of January 1, 2019	$ 998	
Amounts recognized in line items in our Consolidated Balance Sheet at December 31, 2019		
Right-of-Use Assets		
Properties, plants and equipment		
Gross		$ 1,039
Accumulated depreciation, depletion and amortization		(649)
Net properties, plants and equipment*		$ 390
Prepaid expenses and other current assets	$ 40	
Other assets	896	

** Includes proportionately consolidated finance lease assets (net of accumulated depreciation, depletion and amortization) of $335 million.*

	Millions of Dollars	
	Carrying Amount	
	Operating Leases	Finance Leases
Lease Liabilities		
Short-term debt*		$ 87
Other accruals	$ 347	
Long-term debt*		633
Other liabilities and deferred credits	585	
Total lease liabilities	$ 932	$ 720

**Short-term debt and long-term debt include proportionately consolidated finance lease liabilities of $56 million and $579 million, respectively.*

The following table summarizes our lease costs for 2019:

	Millions of Dollars
	2019
Lease Cost*	
Operating lease cost	$ 341
Finance lease cost	
Amortization of right-of-use assets	99
Interest on lease liabilities	37
Short-term lease cost**	77
Total lease cost***	$ 554

**The amounts presented in the table above have not been adjusted to reflect amounts recovered or reimbursed from oil and gas coventurers.*

***Short-term leases are not recorded on our consolidated balance sheet. Our future short-term lease commitments amount to $31 million, of which $18 million is related to leases whose terms have not yet commenced as of December 31, 2019.*

****Variable lease cost and sublease income are immaterial for the period presented and therefore are not included in the table above.*

The following table summarizes the lease terms and discount rates:

	December 31, 2019
Lease Term and Discount Rate	
Weighted-average term (years)	
Operating leases	5.19
Finance leases	8.70
Weighted-average discount rate (percent)	
Operating leases	3.10
Finance leases	5.53

The following table summarizes other lease information for 2019:

		Millions of Dollars
		2019
Other Information*		
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from operating leases	$	203
Operating cash flows from finance leases		27
Financing cash flows from finance leases		81
Right-of-use assets obtained in exchange for operating lease liabilities	$	499
Right-of-use assets obtained in exchange for finance lease liabilities		26

**The amounts presented in the table above have not been adjusted to reflect amounts recovered or reimbursed from oil and gas coventurers. In addition, pursuant to other applicable accounting guidance, lease payments made in connection with preparing another asset for its intended use are reported in the "Cash Flows From Investing Activities" section of our consolidated statement of cash flows.*

The following table summarizes future lease payments for operating and finance leases at December 31, 2019:

		Millions of Dollars	
		Operating Leases	Finance Leases
Maturity of Lease Liabilities			
2020	$	348	120
2021		247	104
2022		130	102
2023		82	88
2024		63	84
Remaining years		149	382
Total*		1,019	880
Less: portion representing imputed interest		(87)	(160)
Total lease liabilities	$	932	720

**Future lease payments for operating and finance leases commencing on or after January 1, 2019, also include payments related to non-lease components in accordance with our election to adopt the optional practical expedient not to separate lease components apart from non-lease components for accounting purposes. In addition, future payments related to operating and finance leases proportionately consolidated by the company have been included in the table on a proportionate basis consistent with our respective ownership interest in the underlying investee company or oil and gas venture.*

At December 31, 2018, future minimum payments due under finance (capital) leases pursuant to ASC Topic 840 were:

		Millions of Dollars
2019	$	118
2020		116
2021		100
2022		98
2023		87
Remaining years		453
Total		972
Less: portion representing imputed interest		(195)
Capital lease obligations	$	777

At December 31, 2018, future undiscounted minimum rental payments due under noncancelable operating leases pursuant to ASC Topic 840 were:

		Millions of Dollars
2019	$	248
2020		425
2021		136
2022		319
2023		54
Remaining years		212
Total		1,394
Less: income from subleases		(7)
Net minimum operating lease payments	$	1,387

For the years ended December 31, operating lease rental expense pursuant to ASC Topic 840 was:

		Millions of Dollars	
		2018	2017
Total rentals	$	253	264
Less: sublease rentals		(16)	(20)
	$	237	244

Note 18—Employee Benefit Plans

Pension and Postretirement Plans

An analysis of the projected benefit obligations for our pension plans and accumulated benefit obligations for our postretirement health and life insurance plans follows:

	Millions of Dollars						
	Pension Benefits					Other Benefits	
		2019		2018		**2019**	2018
		U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation							
Benefit obligation at January 1	**$**	**2,136**	**3,438**	3,236	3,845	**218**	265
Service cost		**79**	**69**	83	81	**1**	1
Interest cost		**79**	**97**	99	107	**8**	8
Plan participant contributions		**-**	**2**	-	2	**20**	22
Plan amendments		**-**	**-**	-	7	**-**	-
Actuarial (gain) loss		**278**	**387**	(44)	(259)	**27**	(10)
Benefits paid		**(253)**	**(147)**	(507)	(143)	**(59)**	(67)
Curtailment		**-**	**(69)**	(4)	(3)	**-**	-
Settlement		**-**	**-**	(730)	-	**-**	-
Recognition of termination benefits		**-**	**1**	3	-	**-**	-
Foreign currency exchange rate change		**-**	**102**	-	(199)	**1**	(1)
Benefit obligation at December 31*	**$**	**2,319**	**3,880**	2,136	3,438	**216**	218
**Accumulated benefit obligation portion of above at December 31:*	*$*	***2,161***	***3,594***	*1,969*	*3,066*		
Change in Fair Value of Plan Assets							
Fair value of plan assets at January 1	**$**	**1,336**	**3,358**	2,541	3,647	**-**	-
Actual return on plan assets		**273**	**529**	(112)	(106)	**-**	-
Company contributions		**235**	**464**	144	156	**39**	45
Plan participant contributions		**-**	**2**	-	2	**20**	22
Benefits paid		**(253)**	**(147)**	(507)	(143)	**(59)**	(67)
Settlement		**-**	**-**	(730)	-	**-**	-
Foreign currency exchange rate change		**-**	**100**	-	(198)	**-**	-
Fair value of plan assets at December 31	**$**	**1,591**	**4,306**	1,336	3,358	**-**	-
Funded Status	**$**	**(728)**	**426**	(800)	(80)	**(216)**	(218)

	Pension Benefits 2019 U.S.	Pension Benefits 2019 Int'l.	Pension Benefits 2018 U.S.	Pension Benefits 2018 Int'l.	Other Benefits 2019	Other Benefits 2018
	Millions of Dollars					
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	$ -	**765**	-	232	-	-
Current liabilities	**(21)**	**(6)**	(59)	(4)	**(42)**	(44)
Noncurrent liabilities	**(707)**	**(333)**	(741)	(308)	**(174)**	(174)
Total recognized	$ **(728)**	**426**	(800)	(80)	**(216)**	(218)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**3.25** %	**2.35**	4.25	3.05	**3.10**	4.05
Rate of compensation increase	**4.00**	**3.35**	4.00	3.65		-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**3.95** %	**2.90**	3.80	2.90	**4.05**	3.30
Expected return on plan assets	**5.80**	**4.10**	5.80	4.30		-
Rate of compensation increase	**4.00**	**3.65**	4.00	3.75		-

For both U.S. and international pensions, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

Included in accumulated other comprehensive income (loss) at December 31 were the following before-tax amounts that had not been recognized in net periodic benefit cost:

	Pension Benefits 2019 U.S.	Pension Benefits 2019 Int'l.	Pension Benefits 2018 U.S.	Pension Benefits 2018 Int'l.	Other Benefits 2019	Other Benefits 2018
	Millions of Dollars					
Unrecognized net actuarial (gain) loss	$ **479**	**227**	516	310	**8**	(21)
Unrecognized prior service cost (credit)	**-**	**(2)**	-	(4)	**(183)**	(216)

		Millions of Dollars					
		Pension Benefits				Other Benefits	
		2019		2018		**2019**	2018
		U.S.	**Int'l.**	U.S.	Int'l.		
Sources of Change in Other Comprehensive Income (Loss)							
Net gain (loss) arising during the period	$	**(79)**	**51**	(177)	17	**(27)**	10
Amortization of actuarial (gain) loss included in income (loss)*		**116**	**32**	249	31	**(2)**	(1)
Net change during the period	$	**37**	**83**	72	48	**(29)**	9
Prior service credit (cost) arising during the period	$	-	-	-	(7)	-	-
Amortization of prior service cost (credit) included in income (loss)		-	**(2)**	-	(5)	**(33)**	(35)
Net change during the period	$	-	**(2)**	-	(12)	**(33)**	(35)

**Includes settlement losses recognized in 2019 and 2018.*

Included in accumulated other comprehensive loss at December 31, 2019, were the following before-tax amounts that are expected to be amortized into net periodic benefit cost during 2020:

		Millions of Dollars		
		Pension Benefits		Other Benefits
		U.S.	Int'l.	
Unrecognized net actuarial (gain) loss	$	**50**	**23**	**1**
Unrecognized prior service credit		-	**(2)**	**(31)**

For our tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $2,073 million, $1,919 million, and $1,635 million, respectively, at December 31, 2019, and $1,871 million, $1,737 million, and $1,373 million, respectively, at December 31, 2018.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $601 million and $542 million, respectively, at December 31, 2019, and were $586 million and $504 million, respectively, at December 31, 2018.

The components of net periodic benefit cost of all defined benefit plans are presented in the following table:

		Millions of Dollars								
		Pension Benefits						Other Benefits		
		2019		2018		2017		**2019**	2018	2017
		U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost										
Service cost	$	**79**	**69**	83	81	89	77	**1**	1	2
Interest cost		**79**	**97**	99	107	118	103	**8**	8	9
Expected return on plan assets		**(74)**	**(138)**	(114)	(155)	(132)	(158)	-	-	-
Amortization of prior service cost (credit)		-	**(2)**	-	(5)	4	(6)	**(33)**	(35)	(36)
Recognized net actuarial loss (gain)		**54**	**32**	53	31	69	50	**(2)**	(1)	(3)
Settlements		**62**	-	196	-	131	-	-	-	-
Net periodic benefit cost	$	**200**	**58**	317	59	279	66	**(26)**	(27)	(28)

The components of net periodic benefit cost, other than the service cost component, are included in the “Other expenses” line item on our consolidated income statement.

In 2018, we purchased a group annuity contract from Prudential and transferred $730 million of future benefit obligations from the U.S. qualified pension plan to Prudential. The purchase of the group annuity contract was funded directly by plan assets of the U.S. qualified pension plan. Effective January 1, 2019, the Cash Balance Account (Title II) of the ConocoPhillips Retirement Plan, a U.S. qualified pension plan, was closed to new entrants. New employees and rehires on or after January 1, 2019, and employees that elected to opt out of Title II will no longer receive pay credits to their Cash Balance Account and instead will be eligible for a Company Retirement Contribution (CRC) as described in the Defined Contribution Plans section.

We recognized pension settlement losses of $62 million in 2019, $196 million in 2018, and $131 million in 2017 as lump-sum benefit payments from certain U.S. pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement losses.

The sale of two ConocoPhillips U.K. subsidiaries completed during the third quarter of 2019 led to a significant reduction of future services of active employees in certain international pension plans, resulting in a curtailment. In conjunction with the recognition of the curtailment, the fair market values of pension plan assets were updated, the pension benefit obligation was remeasured, and the net pension asset decreased by $43 million, resulting in a corresponding decrease to other comprehensive income. This is primarily a result of a decrease in the discount rate from 2.90 percent at December 31, 2018 to 1.80 percent at September 30, 2019 offset by a decrease in the pension benefit obligation from curtailment.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net actuarial gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the U.S. pre-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 7 percent in 2020 that declines to 5 percent by 2028. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes an ultimate health care cost trend rate of 4 percent achieved in 2020 that increases to 5 percent by 2028. A one-percentage-point change in the assumed health care cost trend rate would be immaterial to ConocoPhillips.

Plan Assets—We follow a policy of broadly diversifying pension plan assets across asset classes and individual holdings. As a result, our plan assets have no significant concentrations of credit risk. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. The target allocations for plan assets are 37 percent equity securities, 56 percent debt securities, 6 percent real estate and 1 percent other. Generally, the plan investments are publicly traded, therefore minimizing liquidity risk in the portfolio.

The following is a description of the valuation methodologies used for the pension plan assets. There have been no changes in the methodologies used at December 31, 2019 and 2018.

- Fair values of equity securities and government debt securities categorized in Level 1 are primarily based on quoted market prices in active markets for identical assets and liabilities.
- Fair values of corporate debt securities, agency and mortgage-backed securities and government debt securities categorized in Level 2 are estimated using recently executed transactions and quoted market prices for similar assets and liabilities in active markets and for identical assets and liabilities in markets that are not active. If there have been no market transactions in a particular fixed income security, its fair value is calculated by pricing models that benchmark the security against other securities with actual market prices. When observable quoted market prices are not available, fair value is based on pricing models that use something other than actual market prices (e.g., observable inputs such as benchmark yields, reported trades and issuer spreads for similar securities), and these securities are categorized in Level 3 of the fair value hierarchy.
- Fair values of investments in common/collective trusts are determined by the issuer of each fund based on the fair value of the underlying assets.
- Fair values of mutual funds are based on quoted market prices, which represent the net asset value of shares held.
- Time deposits are valued at cost, which approximates fair value.
- Cash is valued at cost, which approximates fair value. Fair values of international cash equivalents categorized in Level 2 are valued using observable yield curves, discounting and interest rates. U.S. cash balances held in the form of short-term fund units that are redeemable at the measurement date are categorized as Level 2.
- Fair values of exchange-traded derivatives classified in Level 1 are based on quoted market prices. For other derivatives classified in Level 2, the values are generally calculated from pricing models with market input parameters from third-party sources.
- Fair values of insurance contracts are valued at the present value of the future benefit payments owed by the insurance company to the plans' participants.
- Fair values of real estate investments are valued using real estate valuation techniques and other methods that include reference to third-party sources and sales comparables where available.

- A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract, which is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. The participating interest is classified as Level 3 in the fair value hierarchy as the fair value is determined via a combination of quoted market prices, recently executed transactions, and an actuarial present value computation for contract obligations. At December 31, 2019, the participating interest in the annuity contract was valued at $95 million and consisted of $235 million in debt securities, less $140 million for the accumulated benefit obligation covered by the contract. At December 31, 2018, the participating interest in the annuity contract was valued at $84 million and consisted of $228 million in debt securities, less $144 million for the accumulated benefit obligation covered by the contract. The net change from 2018 to 2019 is due to an increase in the fair value of the underlying investments of $7 million offset by a decrease in the present value of the contract obligation of $4 million. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

The fair values of our pension plan assets at December 31, by asset class were as follows:

		Millions of Dollars							
		U.S.				International			
		Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2019									
Equity securities									
U.S.	$	**94**	**-**	**7**	**101**	**435**	**-**	**-**	**435**
International		**98**	**-**	**-**	**98**	**266**	**-**	**-**	**266**
Mutual funds		**93**	**-**	**-**	**93**	**245**	**267**	**-**	**512**
Debt securities									
Government		**-**	**-**	**-**	**-**	**1,412**	**-**	**-**	**1,412**
Corporate		**-**	**2**	**-**	**2**	**-**	**-**	**-**	**-**
Mutual funds		**-**	**-**	**-**	**-**	**392**	**-**	**-**	**392**
Cash and cash equivalents		**-**	**-**	**-**	**-**	**98**	**-**	**-**	**98**
Derivatives		**-**	**-**	**-**	**-**	**11**	**-**	**-**	**11**
Real estate		**-**	**-**	**-**	**-**	**-**	**-**	**132**	**132**
Total in fair value hierarchy	**$**	**285**	**2**	**7**	**294**	**2,859**	**267**	**132**	**3,258**
Investments measured at net asset value*									
Equity securities									
Common/collective trusts	$	**-**	**-**	**-**	**457**	**-**	**-**	**-**	**167**
Debt securities									
Common/collective trusts		**-**	**-**	**-**	**637**	**-**	**-**	**-**	**760**
Cash and cash equivalents		**-**	**-**	**-**	**25**	**-**	**-**	**-**	**-**
Real estate		**-**	**-**	**-**	**83**	**-**	**-**	**-**	**112**
Total**	**$**	**285**	**2**	**7**	**1,496**	**2,859**	**267**	**132**	**4,297**

**In accordance with FASB ASC Topic 715, "Compensation—Retirement Benefits," certain investments that are to be measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Change in Fair Value of Plan Assets.*

***Excludes the participating interest in the insurance annuity contract with a net asset of $95 million and net receivables related to security transactions of $9 million.*

The fair values of our pension plan assets at December 31, by asset class were as follows:

	Millions of Dollars							
	U.S.				International			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2018								
Equity securities								
U.S.	$ 74	-	20	94	371	-	-	371
International	80	-	-	80	241	-	-	241
Mutual funds	76	-	-	76	213	181	-	394
Debt securities								
Government	-	-	-	-	889	-	-	889
Corporate	-	2	-	2	-	-	-	-
Mutual funds	-	-	-	-	363	-	-	363
Cash and cash equivalents	-	-	-	-	71	-	-	71
Time deposits	-	-	-	-	6	-	-	6
Derivatives	-	-	-	-	(17)	-	-	(17)
Real estate	-	-	-	-	-	-	124	124
Total in fair value hierarchy	$ 230	2	20	252	2,137	181	124	2,442
Investments measured at net asset value*								
Equity securities								
Common/collective trusts	$ -	-	-	364	-	-	-	153
Debt securities								
Common/collective trusts	-	-	-	548	-	-	-	641
Cash and cash equivalents	-	-	-	5	-	-	-	-
Real estate	-	-	-	80	-	-	-	109
Total**	$ 230	2	20	1,249	2,137	181	124	3,345

**In accordance with FASB ASC Topic 715, "Compensation—Retirement Benefits," certain investments that are to be measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Change in Fair Value of Plan Assets.*

***Excludes the participating interest in the insurance annuity contract with a net asset of $84 million and net receivables related to security transactions of $16 million.*

Level 3 activity was not material for all periods.

Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2020, we expect to contribute approximately $350 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $90 million to our international qualified and nonqualified pension and postretirement benefit plans.

The following benefit payments, which are exclusive of amounts to be paid from the insurance annuity contract and which reflect expected future service, as appropriate, are expected to be paid:

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	Int'l.	
2020	$ 447	150	32
2021	270	156	29
2022	250	158	27
2023	217	163	24
2024	220	170	22
2025–2029	822	927	64

Severance Accrual

The following table summarizes our severance accrual activity for the year ended December 31, 2019:

	Millions of Dollars
Balance at December 31, 2018	$ 48
Accruals	**(1)**
Benefit payments	**(24)**
Balance at December 31, 2019	**$ 23**

Of the remaining balance at December 31, 2019, $5 million is classified as short-term.

Defined Contribution Plans

Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 75 percent of their eligible pay, subject to statutory limits, in the CPSP to a choice of approximately 17 investment options. Employees who participate in the CPSP and contribute 1 percent of their eligible pay receive a 6 percent company cash match with a potential company discretionary cash contribution of up to 6 percent. Effective January 1, 2019, new employees, rehires, and employees that elected to opt out of Title II are eligible to receive a CRC of 6 percent of eligible pay into their CPSP. After three years of service with the company, the employee is 100 percent vested in any CRC. Company contributions charged to expense for the CPSP and predecessor plans were $82 million in 2019, $82 million in 2018, and $77 million in 2017.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $30 million in 2019, $31 million in 2018, and $35 million in 2017.

Share-Based Compensation Plans

The 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (the Plan) was approved by shareholders in May 2014. Over its 10-year life, the Plan allows the issuance of up to 79 million shares of our common stock for compensation to our employees and directors; however, as of the effective date of the Plan, (i) any shares of common stock available for future awards under the prior plans and (ii) any shares of common stock represented by awards granted under the prior plans that are forfeited, expire or are cancelled without delivery of shares of common stock or which result in the forfeiture of shares of common stock back to the company shall be available for awards under the Plan, and no new awards shall be granted under the prior plans. Of the 79 million shares available for issuance under the Plan, no more than 40 million shares of common stock are available for incentive stock options. The Human Resources and Compensation Committee of our Board of Directors is authorized to determine the types, terms, conditions and limitations of awards granted. Awards may be granted in the form of, but not limited to, stock options, restricted stock units and performance share units to employees and non-employee directors who contribute to the company's continued success and profitability.

Total share-based compensation expense is measured using the grant date fair value for our equity-classified awards and the settlement date fair value for our liability-classified awards. We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award); or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture. Our share-based compensation programs generally provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. Some of our share-based awards vest ratably (i.e., portions of the award vest at different times) while some of our awards cliff vest (i.e., all of the award vests at the same time). We recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

Compensation Expense—Total share-based compensation expense recognized in income (loss) and the associated tax benefit for the years ended December 31 were as follows:

	Millions of Dollars		
	2019	2018	2017
Compensation cost	$ **274**	265	227
Tax benefit	**71**	64	76

Stock Options—Stock options granted under the provisions of the Plan and prior plans permit purchase of our common stock at exercise prices equivalent to the average fair market value of ConocoPhillips common stock on the date the options were granted. The options have terms of 10 years and generally vest ratably, with one-third of the options awarded vesting and becoming exercisable on each anniversary date following the date of grant. Options awarded to certain employees already eligible for retirement vest within six months of the grant date, but those options do not become exercisable until the end of the normal vesting period. Beginning in 2018, stock option grants were discontinued and replaced with three-year, time-vested restricted stock units which generally will be cash-settled.

The fair market values of the options granted in 2017 were measured on the date of grant using the Black-Scholes-Merton option-pricing model. The weighted-average assumptions used were as follows:

	2017
Assumptions used	
Risk-free interest rate	2.24 %
Dividend yield	4.00 %
Volatility factor	28.12 %
Expected life (years)	6.39

There were no ranges in the assumptions used to determine the fair market values of our options granted in 2017.

We believe our historical volatility for periods prior to the 2012 separation of our Downstream businesses is no longer relevant in estimating expected volatility. For 2017, expected volatility was based on the weighted-average blend of the company's historical stock price volatility from May 1, 2012 (the date of separation of our

Downstream businesses) through the stock option grant date and the average historical stock price volatility of a group of peer companies for the expected term of the options.

The following summarizes our stock option activity for the year ended December 31, 2019:

			Millions of Dollars
	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
Outstanding at December 31, 2018	19,379,677	$ 52.88	$ 214
Exercised	**(1,339,480)**	**36.28**	**39**
Forfeited	-		
Expired or cancelled	-		
Outstanding at December 31, 2019	**18,040,197**	**$ 54.11**	**$ 206**
Vested at December 31, 2019	**17,922,026**	**$ 54.14**	**$ 205**
Exercisable at December 31, 2019	**17,172,815**	**$ 54.33**	**$ 194**

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2019, was 4.43 years, 4.41 years and 4.29 years, respectively. The weighted-average grant date fair value of stock option awards granted during 2017 was $9.18. The aggregate intrinsic value of options exercised was $94 million in 2018 and $4 million in 2017.

During 2019, we received $49 million in cash and realized a tax benefit of $13 million from the exercise of options. At December 31, 2019, the remaining unrecognized compensation expense from unvested options was zero.

Stock Unit Program—Generally, restricted stock units are granted annually under the provisions of the Plan and vest in an aggregate installment on the third anniversary of the grant date. In addition, restricted stock units granted under the Plan for a variable long-term incentive program vest ratably in three equal annual installments beginning on the first anniversary of the grant date. Restricted stock units are also granted ad hoc to attract or retain key personnel, and the terms and conditions under which these restricted stock units vest vary by award.

Stock-Settled

Upon vesting, these restricted stock units are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to retirement eligible employees vest six months from the grant date; however, those units are not issued as common stock until the earlier of separation from the company or the end of the regularly scheduled vesting period. Until issued as stock, most recipients of the restricted stock units receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. The grant date fair market value of these restricted stock units is deemed equal to the average ConocoPhillips stock price on the grant date. The grant date fair market value of units that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that will not be received.

The following summarizes our stock-settled stock unit activity for the year ended December 31, 2019:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2018	7,546,973	$ 43.41	
Granted	**2,045,503**	**67.77**	
Forfeited	**(99,748)**	**62.93**	
Issued	**(3,269,682)**	**34.32**	**$ 225**
Outstanding at December 31, 2019	**6,223,046**	**$ 55.99**	
Not Vested at December 31, 2019	**4,185,141**	**56.17**	

At December 31, 2019, the remaining unrecognized compensation cost from the unvested stock-settled units was $93 million, which will be recognized over a weighted-average period of 1.71 years, the longest period being 2.73 years. The weighted-average grant date fair value of stock unit awards granted during 2018 and 2017 was $52.45 and $48.77, respectively. The total fair value of stock units issued during 2018 and 2017 was $154 million and $159 million, respectively.

Cash-Settled

Beginning in 2018, cash-settled executive restricted stock units replaced the stock option program. These restricted stock units, subject to elections to defer, will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet. Units awarded to retirement eligible employees vest six months from the grant date; however, those units are not settled until the earlier of separation from the company or the end of the regularly scheduled vesting period. Compensation expense is initially measured using the average fair market value of ConocoPhillips common stock and is subsequently adjusted, based on changes in the ConocoPhillips stock price through the end of each subsequent reporting period, through the settlement date. Recipients receive an accrued reinvested dividend equivalent that is charged to compensation expense. The accrued reinvested dividend is paid at the time of settlement, subject to the terms and conditions of the award.

The following summarizes our cash-settled stock unit activity for the year ended December 31, 2019:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2018	376,608	$ 62.21	
Granted	**319,552**	**68.20**	
Forfeited	**(6,914)**	**61.35**	
Issued	**(92,255)**	**61.61**	**$ 6**
Outstanding at December 31, 2019	**596,991**	**$ 64.54**	
Not Vested at December 31, 2019	**153,457**	**64.54**	

At December 31, 2019, the remaining unrecognized compensation cost from the unvested cash-settled units was $5 million, which will be recognized over a weighted-average period of 1.70 years, the longest period being 2.12 years. The weighted-average grant date fair value of stock unit awards granted during 2018 was $53.68. The total fair value of stock units issued during 2018 was $1 million.

Performance Share Program—Under the Plan, we also annually grant restricted performance share units (PSUs) to senior management. These PSUs are authorized three years prior to their effective grant date (the performance period). Compensation expense is initially measured using the average fair market value of ConocoPhillips common stock and is subsequently adjusted, based on changes in the ConocoPhillips stock price through the end of each subsequent reporting period, through the grant date for stock-settled awards and the settlement date for cash-settled awards.

Stock-Settled

For performance periods beginning before 2009, PSUs do not vest until the employee becomes eligible for retirement by reaching age 55 with five years of service, and restrictions do not lapse until the employee separates from the company. With respect to awards for performance periods beginning in 2009 through 2012, PSUs do not vest until the earlier of the date the employee becomes eligible for retirement by reaching age 55 with five years of service or five years after the grant date of the award, and restrictions do not lapse until the earlier of the employee's separation from the company or five years after the grant date (although recipients can elect to defer the lapsing of restrictions until separation). We recognize compensation expense for these awards beginning on the grant date and ending on the date the PSUs are scheduled to vest. Since these awards are authorized three years prior to the grant date, for employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Until issued as stock, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to retained earnings. Beginning in 2013, PSUs authorized for future grants will vest, absent employee election to defer, upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. PSUs are settled by issuing one share of ConocoPhillips common stock per unit.

The following summarizes our stock-settled Performance Share Program activity for the year ended December 31, 2019:

			Millions of Dollars
	Stock Units	Weighted-Average Grant Date Fair Value	Total Fair Value
Outstanding at December 31, 2018	2,335,542	$ 50.45	
Granted	**77,841**	**68.90**	
Forfeited	-		
Issued	**(388,559)**	**53.66**	**$ 25**
Outstanding at December 31, 2019	**2,024,824**	**$ 50.55**	
Not Vested at December 31, 2019	**15,616**	**$ 47.80**	

At December 31, 2019, the remaining unrecognized compensation cost from unvested stock-settled performance share awards was zero. The weighted-average grant date fair value of stock-settled PSUs granted during 2018 and 2017 was $53.28 and $49.76, respectively. The total fair value of stock-settled PSUs issued during 2018 and 2017 was $29 million and $57 million, respectively.

Cash-Settled

In connection with and immediately following the separation of our Downstream businesses in 2012, grants of new PSUs, subject to a shortened performance period, were authorized. Once granted, these PSUs vest, absent employee election to defer, on the earlier of five years after the grant date of the award or the date the employee becomes eligible for retirement. For employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Otherwise, we recognize compensation expense beginning on the grant date and ending on the date the PSUs are scheduled to vest. These PSUs are settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and thus are classified as liabilities on the balance sheet. Until settlement occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense.

Beginning in 2013, PSUs authorized for future grants will vest upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending at the conclusion of the performance period. These PSUs will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet. For performance periods beginning before 2018, during the performance period, recipients of the PSUs do not receive a quarterly cash payment of a dividend equivalent, but after the performance period ends, until settlement in cash occurs, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to compensation expense. For the performance period beginning in 2018, recipients of the PSUs receive an accrued reinvested dividend equivalent that is charged to compensation expense. The accrued reinvested dividend is paid at the time of settlement, subject to the terms and conditions of the award.

The following summarizes our cash-settled Performance Share Program activity for the year ended December 31, 2019:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2018	1,131,007	$ 62.21	
Granted	**1,958,043**	**68.90**	
Forfeited	-		
Settled	**(2,479,776)**	**69.10**	**$ 171**
Outstanding at December 31, 2019	**609,274**	**$ 64.54**	
Not Vested at December 31, 2019	**38,487**	**$ 64.54**	

At December 31, 2019, the remaining unrecognized compensation cost from unvested cash-settled performance share awards was zero. The weighted-average grant date fair value of cash-settled PSUs granted during 2018 and 2017 was $53.28 and $49.76, respectively. The total fair value of cash-settled performance share awards settled during 2018 and 2017 was $22 million and $24 million, respectively.

From inception of the Performance Share Program through 2013, approved PSU awards were granted after the conclusion of performance periods. Beginning in February 2014, initial target PSU awards are issued near the beginning of new performance periods. These initial target PSU awards will terminate at the end of the performance periods and will be settled after the performance periods have ended. Also in 2014, initial target PSU awards were issued for open performance periods that began in prior years. For the open performance period beginning in 2012, the initial target PSU awards terminated at the end of the three-year performance period and were replaced with approved PSU awards. For the open performance period beginning in 2013, the initial target PSU awards terminated at the end of the three-year performance period and were settled after the performance period ended. There is no effect on recognition of compensation expense.

Other—In addition to the above active programs, we have outstanding shares of restricted stock and restricted stock units that were either issued as part of our non-employee director compensation program for current and former members of the company's Board of Directors or as part of an executive compensation program that has been discontinued. Generally, the recipients of the restricted shares or units receive a quarterly dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2019:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2018	1,107,315	$ 46.57	
Granted	**64,063**	**63.58**	
Cancelled	**(2,307)**	**23.73**	
Issued	**(177,163)**	**49.23**	**$ 11**
Outstanding at December 31, 2019	**991,908**	**$ 47.24**	

At December 31, 2019, all outstanding restricted stock and restricted stock units were fully vested and there was no remaining compensation cost to be recorded. The weighted-average grant date fair value of awards granted during 2018 and 2017 was $62.01 and $48.87, respectively. The total fair value of awards issued during 2018 and 2017 was $17 million and $4 million, respectively.

Note 19—Income Taxes

Income taxes charged to net income (loss) were:

	Millions of Dollars		
	2019	2018	2017
Income Taxes			
Federal			
Current	$ **18**	4	79
Deferred	**(113)**	545	(3,046)
Foreign			
Current	**2,545**	3,273	1,729
Deferred	**(323)**	(166)	(510)
State and local			
Current	**148**	108	51
Deferred	**(8)**	(96)	(125)
	$ **2,267**	3,668	(1,822)

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

		Millions of Dollars	
		2019	2018
Deferred Tax Liabilities			
PP&E and intangibles	**$**	**8,660**	8,004
Inventory		**35**	60
Deferred state income tax		**-**	61
Other		**234**	156
Total deferred tax liabilities		**8,929**	8,281
Deferred Tax Assets			
Benefit plan accruals		**542**	641
Asset retirement obligations and accrued environmental costs		**2,339**	2,891
Investments in joint ventures		**1,722**	104
Other financial accruals and deferrals		**777**	330
Loss and credit carryforwards		**8,968**	2,378
Other		**345**	398
Total deferred tax assets		**14,693**	6,742
Less: valuation allowance		**(10,214)**	(3,040)
Net deferred tax assets		**4,479**	3,702
Net deferred tax liabilities	**$**	**4,450**	4,579

At December 31, 2019, noncurrent assets and liabilities included deferred taxes of $184 million and $4,634 million, respectively. At December 31, 2018, noncurrent assets and liabilities included deferred taxes of $442 million and $5,021 million, respectively.

At December 31, 2019, the components of our loss and credit carryforwards before and after consideration of the applicable valuation allowances were:

		Millions of Dollars		
		Gross Deferred Tax Asset	Net Deferred Tax Asset After Valuation Allowance	Expiration of Net Deferred Tax Asset
U.S. foreign tax credits	$	7,696	14	2028
U.S. general business credits		250	250	2036-2038
U.S. capital loss		202	32	2024
State net operating losses and tax credits		370	50	Various
Foreign net operating losses and tax credits		450	413	Post 2025
	$	8,968	759	

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2019, valuation allowances increased a total of $7,174 million. The increase primarily relates to deferred tax assets recognized during 2019 as a result of the finalization of rules related to the U.S. Tax Cuts and Jobs Act (Tax Legislation including ongoing issuance of tax regulations related to such legislation), as further discussed below. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects deferred tax assets, net of valuation allowance, will primarily be realized as offsets to reversing deferred tax liabilities.

On December 2, 2019, the Internal Revenue Service finalized foreign tax credit regulations related to the 2017 Tax Cuts and Jobs Act. Due to the finalization of these regulations, in the fourth quarter of 2019 we recognized $151 million of net deferred tax assets. Correspondingly, we recorded $6,642 million of existing foreign tax credit carryovers where recognition was previously considered to be remote. Present legislation still makes their realization unlikely and therefore these credits have been offset with a full valuation allowance.

At December 31, 2019, unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $4,196 million. Deferred income taxes have not been provided on this amount, as we do not plan to initiate any action that would require the payment of income taxes. The estimated amount of additional tax, primarily local withholding tax, that would be payable on this income if distributed is approximately $210 million.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2019, 2018 and 2017:

	Millions of Dollars			
		2019	2018	2017
Balance at January 1	$	**1,081**	882	381
Additions based on tax positions related to the current year		**9**	268	612
Additions for tax positions of prior years		**120**	43	109
Reductions for tax positions of prior years		**(22)**	(73)	(129)
Settlements		**(9)**	(35)	(5)
Lapse of statute		**(2)**	(4)	(86)
Balance at December 31	$	**1,177**	1,081	882

Included in the balance of unrecognized tax benefits for 2019, 2018 and 2017 were $1,100 million, $1,081 million and $882 million, respectively, which, if recognized, would impact our effective tax rate. The balance of the unrecognized tax benefits increased in 2019 mainly due to the treatment of our PDVSA settlement. The balance of the unrecognized tax benefits increased in 2018 mainly due to the treatment of distributions from certain foreign subsidiaries. The balance of unrecognized tax benefits increased in 2017 mainly due to the recognition of a U.S. worthless securities deduction that we do not believe will generate a cash tax benefit. See Note 13—Contingencies and Commitments, for more information on the PDVSA settlement.

At December 31, 2019, 2018 and 2017, accrued liabilities for interest and penalties totaled $42 million, $45 million and $54 million, respectively, net of accrued income taxes. Interest and penalties resulted in a benefit to earnings of $3 million in 2019, a benefit to earnings of $4 million in 2018, and no impact to earnings in 2017.

We file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: U.K. (2015), Canada (2014), U.S. (2014) and Norway (2018). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. Consequently, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

The amounts of U.S. and foreign income (loss) before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

	Millions of Dollars			Percent of Pre-Tax Income (Loss)		
	2019	2018	2017	**2019**	2018	2017
Income (loss) before income taxes						
United States	$ **4,704**	2,867	(5,250)	**49.4 %**	28.7	200.8
Foreign	**4,820**	7,106	2,635	**50.6**	71.3	(100.8)
	$ **9,524**	9,973	(2,615)	**100.0 %**	100.0	100.0
Federal statutory income tax	$ **2,000**	2,095	(915)	**21.0 %**	21.0	35.0
Non-U.S. effective tax rates	**1,399**	1,766	625	**14.7**	17.7	(23.9)
Tax Legislation	-	(10)	(852)	-	(0.1)	32.6
Canada disposition	-	-	(1,277)	-	-	48.8
U.K. disposition	**(732)**	(150)	-	**(7.7)**	(1.5)	-
Recovery of outside basis	**(77)**	(21)	(962)	**(0.8)**	(0.2)	36.8
Adjustment to tax reserves	**9**	(4)	881	**0.1**	-	(33.7)
Adjustment to valuation allowance	**(225)**	(26)	-	**(2.4)**	(0.3)	-
APLNG impairment	-	-	834	-	-	(31.9)
State income tax	**123**	135	(84)	**1.3**	1.4	3.2
Malaysia Deepwater Incentive	**(164)**	-	-	**(1.7)**	-	-
Enhanced oil recovery credit	**(27)**	(99)	(68)	**(0.3)**	(1.0)	2.6
Other	**(39)**	(18)	(4)	**(0.4)**	(0.2)	0.2
	$ **2,267**	3,668	(1,822)	**23.8 %**	36.8	69.7

Our effective tax rate for 2019 was favorably impacted by the sale of two of our U.K. subsidiaries. The disposition generated a before-tax gain of more than $1.7 billion with an associated tax benefit of $335 million. The disposition generated a U.S. capital loss of approximately $2.1 billion which has generated a U.S. tax benefit of approximately $285 million. The remaining U.S. capital loss has been recorded as a deferred tax asset fully offset with a valuation allowance. See Note 5—Asset Acquisitions and Dispositions, for additional information on the disposition.

During the third quarter of 2019, we received final partner approval in Malaysia Block G to claim certain deepwater tax credits. As a result, we recorded an income tax benefit of $164 million.

The decrease in the effective tax rate for 2018 was primarily due to the impact of the Clair Field disposition in the U.K. and our overall income position, partially offset by our mix of income among taxing jurisdictions.

Our effective tax rate for 2018 was favorably impacted by the sale of a U.K. subsidiary to BP. The subsidiary held 16.5 percent of our 24 percent interest in the BP-operated Clair Field in the U.K. The disposition generated a before-tax gain of $715 million with no associated tax cost. See Note 5—Asset Acquisitions and Dispositions, for additional information on the disposition.

Tax Legislation was enacted in the U.S. on December 22, 2017, reducing the U.S. federal corporate income tax rate to 21 percent from 35 percent, requiring companies to pay a one-time transition tax on earnings of certain foreign subsidiaries that were previously tax deferred and creating new taxes on certain foreign-sourced earnings.

SAB 118 measurement period
We applied the guidance in Staff Accounting Bulletin No. 118 when accounting for the enactment-date effects of Tax Legislation in 2017 and throughout 2018. At December 31, 2017, we had not completed our accounting for all the enactment-date income tax effects of Tax Legislation under ASC 740, Income Taxes, for the remeasurement of deferred tax assets and liabilities and the one-time transition tax. As of December 31, 2018, we had completed our accounting for all the enactment-date income tax effects of Tax Legislation. As further discussed below, during 2018, we recognized adjustments of $10 million to the provisional amounts recorded at December 31, 2017, and included these adjustments as a component of income tax provision.

Provisional Amounts—Foreign tax effects
The one-time transition tax is based on our total post-1986 earnings, the tax on which we previously deferred from U.S. income taxes under U.S. law. We estimated at December 31, 2017, that we would not incur a one-time transition tax. Upon further analyses of Tax Legislation and Notices and regulations issued and proposed by the U.S. Department of the Treasury and the Internal Revenue Service, we finalized our calculations of the transition tax liability during 2018. Based upon this analysis, we did not incur a one-time transition tax.

As a result of the Tax Legislation, we removed the indefinite reinvestment assertion on one of our foreign subsidiaries and recorded a tax expense of $56 million in the fourth quarter of 2017.

Deferred tax assets and liabilities
As of December 31, 2017, we remeasured certain deferred tax assets and liabilities based on the rates at which they were expected to reverse in the future (which was generally 21 percent), by recording a provisional amount of $908 million. Upon further analysis of certain aspects of Tax Legislation and refinement of our calculations during the 12 months ended December 31, 2018, we adjusted our provisional amount by $10 million, which is included as a component of income tax expense.

Global intangible low-taxed income (GILTI)
We have elected to account for GILTI in the year the tax is incurred. For 2019 and 2018, the current-year U.S. income tax impact related to GILTI activities is immaterial.

Our effective tax rate in 2017 was favorably impacted by a tax benefit of $1,277 million related to the Canada disposition. This tax benefit was primarily associated with a deferred tax recovery related to the Canadian capital gains exclusion component of the 2017 Canada disposition and the recognition of previously unrealizable Canadian capital asset tax basis. The Canada disposition, along with the associated restructuring of our Canadian operations, may generate an additional tax benefit of $822 million. However, since we believe it is not likely we will receive a corresponding cash tax savings, this $822 million benefit has been offset by a full tax reserve. See Note 5—Asset Acquisitions and Dispositions for additional information on our Canada disposition.

The impairment of our APLNG investment in the second quarter of 2017 did not generate a tax benefit. See the "APLNG" section of Note 6—Investments, Loans and Long-Term Receivables, for information on the impairment of our APLNG investment.

Certain operating losses in jurisdictions outside of the U.S. only yield a tax benefit in the U.S. as a worthless security deduction. For 2019, 2018 and 2017, before consideration of unrecorded tax benefits discussed above, the amount of the tax benefit was $9 million, $36 million and $962 million, respectively.

Note 20—Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss in the equity section of the balance sheet included:

	Millions of Dollars			
	Defined Benefit Plans	Net Unrealized Loss on Securities	Foreign Currency Translation	Accumulated Other Comprehensive Loss
December 31, 2016	$ (547)	-	(5,646)	(6,193)
Other comprehensive income (loss)	147	(58)	586	675
December 31, 2017	(400)	(58)	(5,060)	(5,518)
Other comprehensive income (loss)	39	-	(642)	(603)
Cumulative effect of adopting ASU No. 2016-01*	-	58	-	58
December 31, 2018	(361)	-	(5,702)	(6,063)
Other comprehensive income	**51**	-	**695**	**746**
Cumulative effect of adopting ASU No. 2018-02**	**(40)**	-	-	**(40)**
December 31, 2019	**$ (350)**	-	**(5,007)**	**(5,357)**

**We adopted ASU No. 2016-01, "Recognition and Measurement of Financial Assets and Liabilities," beginning January 1, 2018.*
***See Note 2—Changes in Accounting Principles for additional information.*

During 2019, we recognized $483 million of foreign currency translation adjustments related to the completion of our sale of two ConocoPhillips U.K. subsidiaries. For additional information related to this disposition, see Note 5—Asset Acquisitions and Dispositions.

There were no items within accumulated other comprehensive loss related to noncontrolling interests.

The following table summarizes reclassifications out of accumulated other comprehensive loss during the years ended December 31:

	Millions of Dollars	
	2019	2018
Defined Benefit Plans	**$ 88**	189
Above amounts are included in the computation of net periodic benefit cost and are presented net of tax expense of:	***$ 23***	*50*

See Note 18—Employee Benefit Plans, for additional information.

Note 21—Cash Flow Information

		Millions of Dollars	
	2019	2018	2017
Noncash Investing Activities			
Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations	$ **205**	395	(37)
Increase (decrease) in assets and liabilities acquired in a nonmonetary exchange*			
Accounts receivable	-	(44)	-
Inventories	-	42	-
Investments and long-term receivables	-	15	-
PP&E	-	1,907	-
Other long-term assets	-	(9)	-
Accounts payable	-	7	-
Accrued income and other taxes	-	40	-
Cash Payments			
Interest	$ **810**	772	1,163
Income taxes	**2,905**	2,976	1,168
Net Sales (Purchases) of Investments			
Short-term investments purchased	$ **(4,902)**	(1,953)	(6,617)
Short-term investments sold	**2,138**	3,573	4,827
Investments and long-term receivables purchased	**(146)**	-	-
	$ **(2,910)**	1,620	(1,790)

**See Note 5—Asset Acquisitions and Dispositions.*

The following items are included in the “Cash Flows from Operating Activities” section of our consolidated cash flows.

We collected $330 million and $430 million in 2019 and 2018, respectively, from PDVSA under a settlement agreement related to an award issued by the ICC Tribunal in 2018. We collected $262 million and $75 million from Ecuador in 2018 and 2017, respectively, as installment payments related to an agreement reached with Ecuador in 2017. For more information on these settlements, see Note 13—Contingencies and Commitments.

In 2019, we made a $324 million contribution to our U.K. pension plan. We made discretionary payments to our domestic qualified pension plan of $120 million and $600 million in 2018 and 2017, respectively.

In 2017, we recognized a $180 million adverse cash impact from the settlement of cross-currency swap transactions.

Note 22—Other Financial Information

		Millions of Dollars		
		2019	2018	2017
Interest and Debt Expense				
Incurred				
Debt	$	**799**	838	1,114
Other		**36**	67	103
		835	905	1,217
Capitalized		**(57)**	(170)	(119)
Expensed	$	**778**	735	1,098
Other Income				
Interest income	$	**166**	97	112
Unrealized gains (losses) on Cenovus Energy common shares*		**649**	(437)	-
Other, net		**543**	513	417
	$	**1,358**	173	529

**See Note 7—Investment in Cenovus Energy, for additional information.*

Research and Development Expenditures—expensed	$	**82**	78	100
Shipping and Handling Costs	$	**1,008**	1,075	1,050
Foreign Currency Transaction (Gains) Losses—after-tax				
Alaska	$	**-**	-	-
Lower 48		**-**	-	-
Canada		**5**	(11)	3
Europe and North Africa		**-**	(26)	7
Asia Pacific and Middle East		**31**	3	23
Other International		**1**	-	1
Corporate and Other		**21**	21	(3)
	$	**58**	(13)	31

		Millions of Dollars	
		2019	2018
Properties, Plants and Equipment			
Proved properties	$	**88,284** *	100,657
Unproved properties		**3,980** *	4,662
Other		**5,482**	5,278
Gross properties, plants and equipment		**97,746**	110,597
Less: Accumulated depreciation, depletion and amortization		**(55,477)***	(64,899)
Net properties, plants and equipment	$	**42,269**	45,698

**Excludes assets classified as held for sale at December 31, 2019. See Note 5—Asset Acquisitions and Dispositions, for additional information.*

Note 23—Related Party Transactions

Our related parties primarily include equity method investments and certain trusts for the benefit of employees.

Significant transactions with our equity affiliates were:

		Millions of Dollars		
		2019	2018	2017
Operating revenues and other income	$	**89**	98	107
Purchases		**38**	98	99
Operating expenses and selling, general and administrative expenses		**65**	60	59
Net interest (income) expense*		**(13)**	(14)	(13)

**We paid interest to, or received interest from, various affiliates. See Note 6—Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.*

The table above includes transactions with the FCCL Partnership through the date of the sale. See Note 6—Investments, Loans and Long-Term Receivables, for additional information.

Note 24—Sales and Other Operating Revenues

Revenue from Contracts with Customers

The following table provides further disaggregation of our consolidated sales and other operating revenues:

		Millions of Dollars		
		2019	2018	2017
Revenue from contracts with customers	$	**26,106**	28,098	20,525
Revenue from contracts outside the scope of ASC Topic 606				
Physical contracts meeting the definition of a derivative		**6,558**	8,218	8,669
Financial derivative contracts		**(97)**	101	(88)
Consolidated sales and other operating revenues	$	**32,567**	36,417	29,106

Revenues from contracts outside the scope of ASC Topic 606 relate primarily to physical gas contracts at market prices which qualify as derivatives accounted for under ASC Topic 815, "Derivatives and Hedging," and for which we have not elected NPNS. There is no significant difference in contractual terms or the policy for recognition of revenue from these contracts and those within the scope of ASC Topic 606. The following disaggregation of revenues is provided in conjunction with Note 25—Segment Disclosures and Related Information:

		Millions of Dollars		
		2019	2018	2017
Revenue from Outside the Scope of ASC Topic 606 by Segment				
Lower 48	$	**4,989**	6,358	6,302
Canada		**691**	629	864
Europe and North Africa		**878**	1,231	1,503
Physical contracts meeting the definition of a derivative	$	**6,558**	8,218	8,669

		Millions of Dollars		
		2019	2018	2017
Revenue from Outside the Scope of ASC Topic 606 by Product				
Crude oil	$	**804**	1,112	588
Natural gas		**5,313**	6,734	7,811
Other		**441**	372	270
Physical contracts meeting the definition of a derivative	$	**6,558**	8,218	8,669

Practical Expedients

Typically, our commodity sales contracts are less than 12 months in duration; however, in certain specific cases may extend longer, which may be out to the end of field life. We have long-term commodity sales contracts which use prevailing market prices at the time of delivery, and under these contracts, the market-based variable consideration for each performance obligation (i.e., delivery of commodity) is allocated to each wholly unsatisfied performance obligation within the contract. Accordingly, we have applied the practical expedient allowed in ASC Topic 606 and do not disclose the aggregate amount of the transaction price allocated to performance obligations or when we expect to recognize revenues that are unsatisfied (or partially unsatisfied) as of the end of the reporting period.

Receivables and Contract Liabilities

Receivables from Contracts with Customers

At December 31, 2019, the “Accounts and notes receivable” line on our consolidated balance sheet included trade receivables of $2,372 million compared with $2,889 million at December 31, 2018, and included both contracts with customers within the scope of ASC Topic 606 and those that are outside the scope of ASC Topic 606. We typically receive payment within 30 days or less (depending on the terms of the invoice) once delivery is made. Revenues that are outside the scope of ASC Topic 606 relate primarily to physical gas sales contracts at market prices for which we do not elect NPNS and are therefore accounted for as a derivative under ASC Topic 815. There is little distinction in the nature of the customer or credit quality of trade receivables associated with gas sold under contracts for which NPNS has not been elected compared with trade receivables where NPNS has been elected.

Contract Liabilities from Contracts with Customers

We have entered into contractual arrangements where we license proprietary technology to customers related to the optimization process for operating LNG plants. The agreements typically provide for negotiated payments to be made at stated milestones. The payments are not directly related to our performance under the contract and are recorded as deferred revenue to be recognized as revenue when the customer can utilize and benefit from their right to use the license. Payments are received in installments over the construction period.

		Millions of Dollars
Contract Liabilities		
At December 31, 2018	$	**206**
Contractual payments received		**73**
Revenue recognized		**(199)**
At December 31, 2019	$	**80**

We expect to recognize the contract liabilities as of December 31, 2019, as revenue during 2021 and 2022.

Note 25—Segment Disclosures and Related Information

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a worldwide basis. We manage our operations through six operating segments, which are primarily defined by geographic region: Alaska, Lower 48, Canada, Europe and North Africa, Asia Pacific and Middle East, and Other International.

Corporate and Other represents costs not directly associated with an operating segment, such as most interest expense, premiums on early retirement of debt, corporate overhead and certain technology activities, including licensing revenues. Corporate assets include all cash and cash equivalents and short-term investments.

We evaluate performance and allocate resources based on net income (loss) attributable to ConocoPhillips. Segment accounting policies are the same as those in Note 1—Accounting Policies. Intersegment sales are at prices that approximate market.

Analysis of Results by Operating Segment

	Millions of Dollars			
		2019	2018	2017
Sales and Other Operating Revenues				
Alaska	$	**5,483**	5,740	4,224
Lower 48		**15,514**	17,029	12,968
Intersegment eliminations		**(46)**	(40)	(4)
Lower 48		**15,468**	16,989	12,964
Canada		**2,910**	3,184	3,178
Intersegment eliminations		**(1,141)**	(1,160)	(559)
Canada		**1,769**	2,024	2,619
Europe and North Africa		**5,101**	6,635	5,181
Asia Pacific and Middle East		**4,525**	4,861	4,014
Other International		**-**	-	-
Corporate and Other		**221**	168	104
Consolidated sales and other operating revenues	$	**32,567**	36,417	29,106
Depreciation, Depletion, Amortization and Impairments				
Alaska	$	**805**	760	1,026
Lower 48		**3,224**	2,370	6,693
Canada		**232**	324	461
Europe and North Africa		**887**	1,041	1,313
Asia Pacific and Middle East		**1,285**	1,382	3,819
Other International		**-**	-	-
Corporate and Other		**62**	106	134
Consolidated depreciation, depletion, amortization and impairments	$	**6,495**	5,983	13,446

The market for our products is large and diverse, therefore, our sales and other operating revenues are not dependent upon any single customer.

		Millions of Dollars	
	2019	2018	2017
Equity in Earnings of Affiliates			
Alaska	$ **7**	6	7
Lower 48	**(159)**	1	5
Canada	**-**	-	197
Europe and North Africa	**16**	16	10
Asia Pacific and Middle East	**915**	1,051	553
Other International	**-**	-	-
Corporate and Other	**-**	-	-
Consolidated equity in earnings of affiliates	$ **779**	1,074	772
Income Taxes			
Alaska	$ **472**	376	(689)
Lower 48	**137**	474	(2,453)
Canada	**(43)**	(96)	(616)
Europe and North Africa	**1,435**	2,265	1,165
Asia Pacific and Middle East	**491**	722	351
Other International	**8**	30	21
Corporate and Other	**(233)**	(103)	399
Consolidated income taxes	$ **2,267**	3,668	(1,822)
Net Income (Loss) Attributable to ConocoPhillips			
Alaska	$ **1,520**	1,814	1,466
Lower 48	**436**	1,747	(2,371)
Canada	**279**	63	2,564
Europe and North Africa	**2,724**	1,866	553
Asia Pacific and Middle East	**1,929**	2,070	(1,098)
Other International	**263**	364	167
Corporate and Other	**38**	(1,667)	(2,136)
Consolidated net income (loss) attributable to ConocoPhillips	$ **7,189**	6,257	(855)
Investments in and Advances to Affiliates			
Alaska	$ **83**	86	56
Lower 48	**35**	378	402
Canada	**-**	-	-
Europe and North Africa	**54**	55	55
Asia Pacific and Middle East	**8,281**	8,821	9,077
Other International	**-**	-	-
Corporate and Other	**-**	-	-
Consolidated investments in and advances to affiliates	$ **8,453**	9,340	9,590

	Millions of Dollars		
	2019	2018	2017
Total Assets			
Alaska	$ **15,453**	14,648	12,108
Lower 48	**14,425**	14,888	14,632
Canada	**6,350**	5,748	6,214
Europe and North Africa	**8,121**	9,883	11,870
Asia Pacific and Middle East	**14,716**	16,151	16,985
Other International	**285**	89	97
Corporate and Other	**11,164**	8,573	11,456
Consolidated total assets	$ **70,514**	69,980	73,362
Capital Expenditures and Investments			
Alaska	$ **1,513**	1,298	815
Lower 48	**3,394**	3,184	2,136
Canada	**368**	477	202
Europe and North Africa	**708**	877	872
Asia Pacific and Middle East	**584**	718	482
Other International	**8**	6	21
Corporate and Other	**61**	190	63
Consolidated capital expenditures and investments	$ **6,636**	6,750	4,591
Interest Income and Expense			
Interest income			
Alaska	$ **-**	-	-
Lower 48	**-**	-	-
Canada	**-**	-	-
Europe and North Africa	**2**	2	2
Asia Pacific and Middle East	**15**	15	9
Other International	**-**	-	-
Corporate and Other	**149**	80	101
Interest and debt expense			
Corporate and Other	$ **778**	735	1,098
Sales and Other Operating Revenues by Product			
Crude oil	$ **18,482**	19,571	13,260
Natural gas	**8,715**	10,720	10,773
Natural gas liquids	**814**	1,114	1,102
Other*	**4,556**	5,012	3,971
Consolidated sales and other operating revenues by product	$ **32,567**	36,417	29,106

**Includes LNG and bitumen.*

Geographic Information

	Millions of Dollars						
	Sales and Other Operating Revenues[1]			Long-Lived Assets[2]			
		2019	2018	2017	**2019**	2018	2017
United States[3]	$	**21,159**	22,740	17,204	**26,566**	26,838	23,623
Australia and Timor-Leste[4]		**1,647**	1,798	1,448	**7,228**	9,301	9,657
Canada		**1,769**	2,024	2,619	**5,769**	5,333	5,613
China		**772**	836	712	**1,447**	1,380	1,275
Indonesia		**875**	886	757	**605**	669	758
Libya		**1,103**	1,142	586	**668**	679	699
Malaysia		**1,230**	1,346	1,103	**1,871**	2,327	2,736
Norway		**2,349**	2,886	2,348	**5,258**	5,582	6,154
United Kingdom		**1,649**	2,606	2,248	**2**	1,583	3,335
Other foreign countries		**14**	153	81	**1,308**	1,346	1,423
Worldwide consolidated	$	**32,567**	36,417	29,106	**50,722**	55,038	55,273

(1) Sales and other operating revenues are attributable to countries based on the location of the selling operation.
(2) Defined as net PP&E plus equity investments and advances to affiliated companies.
(3) Long-lived assets do not include $426 million of net PP&E associated with assets held for sale as of December 31, 2019. See Note 5—Acquisitions and Dispositions, for additional information.
(4) Long-lived assets do not include $1,236 million of net PP&E associated with assets held for sale as of December 31, 2019. See Note 5—Acquisitions and Dispositions, for additional information.

Note 26—New Accounting Standards

In June 2016, the FASB issued ASU No. 2016-13, “Measurement of Credit Losses on Financial Instruments” (ASU No. 2016-13), which sets forth the current expected credit loss model, a new forward-looking impairment model for certain financial instruments based on expected losses rather than incurred losses. The ASU is effective for interim and annual periods beginning after December 15, 2019. Entities are required to adopt ASU No. 2016-13 using a modified retrospective approach, subject to certain limited exceptions. The impact of adopting this ASU is not expected to be material to our financial statements.

In accordance with FASB ASC Topic 932, "Extractive Activities—Oil and Gas," and regulations of the SEC, we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates' oil and gas activities in our operating segments. As a result, amounts reported as equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report. Our disclosures by geographic area include the U.S., Canada, Europe, Asia Pacific/Middle East, and Africa. Period end proved reserves, capitalized costs, wells and acreage include held-for-sale assets at December 31, 2019. See Note 5—Asset Acquisitions and Dispositions, in the Notes to Consolidated Financial Statements, for additional information on held-for-sale assets.

As required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on historical 12-month first-of-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to PSCs, which are reported under the "economic interest" method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices, recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2019, approximately 6 percent of our total proved reserves were under PSCs, located in our Asia Pacific/Middle East geographic reporting area, and 6 percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

Reserves Governance

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

Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared with the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence provided by reliable technologies exists that establishes reasonable certainty of economic producibility at greater distances. As defined by SEC regulations, reliable technologies may be used in reserve estimation when they have been demonstrated in the field to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. The technologies and data used in the estimation of our proved reserves include, but are not limited to, performance-based methods, volumetric-based methods, geologic maps, seismic interpretation, well logs, well test data, core data, analogy and statistical analysis.

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geoscientists and reservoir engineers in our business units around the world. As part of our internal control process, each business unit's reserves processes and controls are reviewed annually by an internal team which is headed by the company's Manager of Reserves Compliance and Reporting. This team, composed of internal reservoir engineers, geoscientists, finance personnel and a senior representative from DeGolyer and MacNaughton (D&M), a third-party petroleum engineering consulting firm, reviews the business units' reserves for adherence to SEC guidelines and company policy through on-site visits, teleconferences and review of documentation. In addition to providing independent reviews, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting its findings to senior management. The team is responsible for communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year. All of our proved reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips.

During 2019, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2019, were reviewed by D&M. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips' technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating 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 D&M to review its processes and controls was to provide objective third-party input on these processes and controls. D&M's opinion was the general processes and controls employed by ConocoPhillips in estimating its December 31, 2019, proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M's report is included as Exhibit 99 of this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the processes and internal controls used in the preparation of the company's reserves estimates is the Manager of Reserves Compliance and Reporting. This individual holds a master's degree in petroleum engineering. He is a member of the Society of Petroleum Engineers with over 25 years of oil and gas industry experience and has held positions of increasing responsibility in reservoir engineering, subsurface and asset management in the U.S. and several international field locations.

Engineering estimates of the quantities of proved reserves are inherently imprecise. See the "Critical Accounting Estimates" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

Proved Reserves

Years Ended December 31	Crude Oil							
	Millions of Barrels							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed and Undeveloped								
Consolidated operations								
End of 2016	837	506	1,343	13	303	185	203	2,047
Revisions	113	65	178	1	38	32	-	249
Improved recovery	6	-	6	-	-	-	-	6
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	41	210	251	-	-	2	-	253
Production	(60)	(64)	(124)	(1)	(45)	(34)	(7)	(211)
Sales	-	(10)	(10)	(12)	-	-	-	(22)
End of 2017	937	707	1,644	1	296	185	196	2,322
Revisions	72	(90)	(18)	2	24	6	5	19
Improved recovery	2	-	2	-	-	-	-	2
Purchases	233	1	234	-	-	-	-	234
Extensions and discoveries	48	179	227	2	2	1	-	232
Production	(59)	(82)	(141)	(1)	(40)	(33)	(13)	(228)
Sales	-	(12)	(12)	-	(36)	-	-	(48)
End of 2018	1,233	703	1,936	4	246	159	188	2,533
Revisions	40	(36)	4	(1)	18	(5)	23	39
Improved recovery	7	-	7	-	-	-	-	7
Purchases	-	1	1	-	-	-	-	1
Extensions and discoveries	25	226	251	2	-	11	-	264
Production	(74)	(95)	(169)	-	(36)	(31)	(14)	(250)
Sales	-	(2)	(2)	-	(30)	-	-	(32)
End of 2019	1,231	797	2,028	5	198	134	197	2,562
Equity affiliates								
End of 2016	-	-	-	-	-	88	-	88
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(5)
Sales	-	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	83	-	83
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(5)
Sales	-	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	78	-	78
Revisions	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(5)	-	(5)
Sales	-	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	73	-	73
Total company								
End of 2016	837	506	1,343	13	303	273	203	2,135
End of 2017	937	707	1,644	1	296	268	196	2,405
End of 2018	1,233	703	1,936	4	246	237	188	2,611
End of 2019	1,231	797	2,028	5	198	207	197	2,635

Years Ended December 31	Crude Oil							
	Millions of Barrels							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed								
Consolidated operations								
End of 2016	747	256	1,003	13	184	106	203	1,509
End of 2017	828	315	1,143	1	190	121	196	1,651
End of 2018	1,058	346	1,404	2	192	113	185	1,896
End of 2019	1,048	334	1,382	3	149	94	181	1,809
Equity affiliates								
End of 2016	-	-	-	-	-	88	-	88
End of 2017	-	-	-	-	-	83	-	83
End of 2018	-	-	-	-	-	78	-	78
End of 2019	-	-	-	-	-	73	-	73
Undeveloped								
Consolidated operations								
End of 2016	90	250	340	-	119	79	-	538
End of 2017	109	392	501	-	106	64	-	671
End of 2018	175	357	532	2	54	46	3	637
End of 2019	183	463	646	2	49	40	16	753
Equity affiliates								
End of 2016	-	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	-	-	-

Notable changes in proved crude oil reserves in the three years ended December 31, 2019, included:

- Revisions: In 2019, Alaska upward revisions were due to cost and technical revisions of 74 million barrels, partially offset by downward price revisions of 34 million barrels. Upward revisions in Europe and Africa were primarily due to infill drilling and technical revisions. Downward revisions in Lower 48 were due to changes in development timing for specific well locations from the unconventional plays of 71 million barrels and price revisions of 22 million barrels, partially offset by upward revisions related to infill drilling and improved well performance of 57 million barrels.

  In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific well locations from the unconventional plays and are more than offset by increases in planned well locations in the unconventional plays in the extensions and discoveries category. Downward revisions in Lower 48 due to development timing were partially offset by higher prices. Revisions in Alaska, Europe and Asia Pacific/Middle East were primarily due to higher prices.

  In 2017, revisions in Alaska, Lower 48, Europe and Asia Pacific/Middle East were primarily due to higher prices.

- *Purchases:* In 2018, Alaska purchases were due to the Greater Kuparuk Area and Western North Slope acquisitions.

- *Extensions and discoveries*: In 2019, extensions and discoveries in Lower 48 were due to planned development to add specific well locations from the unconventional plays which more than offset the decreases in the revisions category. In Asia Pacific/Middle East, increases were due to sanctioning of development programs in China and Malaysia.

  In 2018, extensions and discoveries in Lower 48 were primarily due to changes in the development strategy to add specific well locations from the unconventional plays. Extensions and discoveries in Alaska were driven by drilling success in Western North Slope.

  In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Permian Unconventional, Eagle Ford and Bakken.

- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets. In 2018, Europe sales were due to the disposition of a subsidiary that held 16.5 percent of our 24 percent interest in the Clair Field in the U.K. In 2017, Canada sales were due to the disposition of a majority of our western Canada assets.

Years Ended December 31	Natural Gas Liquids						
	Millions of Barrels						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Total
Developed and Undeveloped							
Consolidated operations							
End of 2016	107	278	385	48	19	5	457
Revisions	4	29	33	-	2	1	36
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	71	71	-	-	1	72
Production	(5)	(24)	(29)	(3)	(3)	(2)	(37)
Sales	-	(130)	(130)	(44)	-	-	(174)
End of 2017	106	224	330	1	18	5	354
Revisions	5	(25)	(20)	-	1	(1)	(20)
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	69	69	-	1	-	70
Production	(5)	(25)	(30)	-	(3)	(1)	(34)
Sales	-	(21)	(21)	-	-	-	(21)
End of 2018	106	222	328	1	17	3	349
Revisions	(1)	(11)	(12)	-	3	(1)	(10)
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	62	62	1	-	-	63
Production	(5)	(28)	(33)	-	(3)	(1)	(37)
Sales	-	-	-	-	(4)	-	(4)
End of 2019	100	245	345	2	13	1	361
Equity affiliates							
End of 2016	-	-	-	-	-	47	47
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(2)	(2)
Sales	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	45	45
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	(3)
Sales	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	42	42
Revisions	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-
Production	-	-	-	-	-	(3)	(3)
Sales	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	39	39
Total company							
End of 2016	107	278	385	48	19	52	504
End of 2017	106	224	330	1	18	50	399
End of 2018	106	222	328	1	17	45	391
End of 2019	100	245	345	2	13	40	400

Years Ended December 31	Natural Gas Liquids						
	Millions of Barrels						
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Total
Developed							
Consolidated operations							
End of 2016	107	209	316	47	15	5	383
End of 2017	106	101	207	1	16	2	226
End of 2018	106	97	203	-	15	3	221
End of 2019	100	99	199	1	10	1	211
Equity affiliates							
End of 2016	-	-	-	-	-	47	47
End of 2017	-	-	-	-	-	45	45
End of 2018	-	-	-	-	-	42	42
End of 2019	-	-	-	-	-	39	39
Undeveloped							
Consolidated operations							
End of 2016	-	69	69	1	4	-	74
End of 2017	-	123	123	-	2	3	128
End of 2018	-	125	125	1	2	-	128
End of 2019	-	146	146	1	3	-	150
Equity affiliates							
End of 2016	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	-	-

Notable changes in proved NGL reserves in the three years ended December 31, 2019, included:

- *Revisions*: In 2019, downward revisions in Lower 48 were due to changes in development timing for specific well locations from the unconventional plays of 32 million barrels and price revisions of 11 million barrels, partially offset by upward revisions related to infill drilling and improved well performance of 32 million barrels.

  In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific well locations from the unconventional plays and are more than offset by increases in planned well locations in the unconventional plays in the extensions and discoveries category.

  In 2017, revisions in Lower 48 were primarily due to higher prices.

- *Extensions and discoveries*: In 2019, extensions and discoveries in Lower 48 were due to planned development to add specific well locations from the unconventional plays which more than offset the decreases in the revisions category.

  In 2018, extensions and discoveries in Lower 48 were primarily due to changes in the development strategy to add specific well locations from the unconventional plays.

  In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Permian Unconventional, Eagle Ford and Bakken.

- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets. In 2018, Lower 48 sales were primarily due to the disposition of our interests in the Barnett. In 2017, Lower 48 sales were due to the disposition of our interests in the San Juan Basin and Panhandle assets, while Canada sales were due to the disposition of a majority of our western Canada assets.

Years Ended December 31	Natural Gas							
	Billions of Cubic Feet							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed and Undeveloped								
Consolidated operations								
End of 2016	2,102	4,714	6,816	1,037	1,238	1,526	227	10,844
Revisions	287	460	747	8	167	16	-	938
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	2	582	584	3	-	23	-	610
Production	(71)	(338)	(409)	(71)	(188)	(267)	(3)	(938)
Sales	-	(2,885)	(2,885)	(966)	-	-	-	(3,851)
End of 2017	2,320	2,533	4,853	11	1,217	1,298	224	7,603
Revisions	150	(283)	(133)	9	86	4	-	(34)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	335	1	336	-	-	-	-	336
Extensions and discoveries	2	527	529	11	110	23	-	673
Production	(71)	(237)	(308)	(5)	(188)	(246)	(10)	(757)
Sales	-	(223)	(223)	-	(13)	-	-	(236)
End of 2018	2,736	2,318	5,054	26	1,212	1,079	214	7,585
Revisions	30	(113)	(83)	(2)	160	147	21	243
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	2	2	-	-	-	-	2
Extensions and discoveries	7	483	490	23	-	1	-	514
Production	(85)	(252)	(337)	(4)	(178)	(250)	(11)	(780)
Sales	-	(7)	(7)	-	(298)	-	-	(305)
End of 2019	2,688	2,431	5,119	43	896	977	224	7,259
Equity affiliates								
End of 2016	-	-	-	-	-	4,381	-	4,381
Revisions	-	-	-	-	-	111	-	111
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	185	-	185
Production	-	-	-	-	-	(374)	-	(374)
Sales	-	-	-	-	-	-	-	-
End of 2017	-	-	-	-	-	4,303	-	4,303
Revisions	-	-	-	-	-	280	-	280
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	362	-	362
Production	-	-	-	-	-	(381)	-	(381)
Sales	-	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	4,564	-	4,564
Revisions	-	-	-	-	-	(7)	-	(7)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	252	-	252
Production	-	-	-	-	-	(388)	-	(388)
Sales	-	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	4,421	-	4,421
Total company								
End of 2016	2,102	4,714	6,816	1,037	1,238	5,907	227	15,225
End of 2017	2,320	2,533	4,853	11	1,217	5,601	224	11,906
End of 2018	2,736	2,318	5,054	26	1,212	5,643	214	12,149
End of 2019	2,688	2,431	5,119	43	896	5,398	224	11,680

Years Ended December 31	Natural Gas							
	Billions of Cubic Feet							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed								
Consolidated operations								
End of 2016	2,094	4,199	6,293	1,031	998	1,188	227	9,737
End of 2017	2,310	1,597	3,907	11	997	945	224	6,084
End of 2018	2,720	1,427	4,147	17	1,052	758	214	6,188
End of 2019	2,601	1,398	3,999	30	697	843	224	5,793
Equity affiliates								
End of 2016	-	-	-	-	-	4,110	-	4,110
End of 2017	-	-	-	-	-	4,044	-	4,044
End of 2018	-	-	-	-	-	4,059	-	4,059
End of 2019	-	-	-	-	-	3,898	-	3,898
Undeveloped								
Consolidated operations								
End of 2016	8	515	523	6	240	338	-	1,107
End of 2017	10	936	946	-	220	353	-	1,519
End of 2018	16	891	907	9	160	321	-	1,397
End of 2019	87	1,033	1,120	13	199	134	-	1,466
Equity affiliates								
End of 2016	-	-	-	-	-	271	-	271
End of 2017	-	-	-	-	-	259	-	259
End of 2018	-	-	-	-	-	505	-	505
End of 2019	-	-	-	-	-	523	-	523

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed in production operations. Quantities consumed in production operations are not significant in the periods presented. The value of net production consumed in operations is not reflected in net revenues and production expenses, nor do the volumes impact the respective per unit metrics.

Reserve volumes include natural gas to be consumed in operations of 3,141 Bcf, 3,131 Bcf, and 3,825 Bcf as of December 31, 2019, 2018 and 2017, respectively. These volumes are not included in the calculation of our Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities.

Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Notable changes in proved natural gas reserves in the three years ended December 31, 2019, included:

- *Revisions*: In 2019, upward revisions in Europe were due to technical and cost revisions. In Asia Pacific/Middle East upward revisions were primarily due to the Indonesia Corridor PSC term extension. Downward revisions in Lower 48 were due to changes in development timing for specific well locations from the unconventional plays of 207 Bcf and price revisions of 125 Bcf, partially offset by upward revisions related to infill drilling and improved well performance of 219 Bcf.

  In 2018, downward revisions in Lower 48 were primarily due to changes in development timing for specific well locations from the unconventional plays and are more than offset by increases in planned well locations in the unconventional plays in the extensions and discoveries category. Downward revisions in Lower 48 due to development timing were partially offset by higher prices. Revisions in Alaska, Canada, Europe and our equity affiliates in Asia Pacific/Middle East were primarily due to higher prices.

  In 2017, revisions in Alaska, Lower 48 and Europe were primarily due to higher prices.

- *Purchases*: In 2018, Alaska purchases were due to the Greater Kuparuk Area and Western North Slope acquisitions.

- *Extensions and discoveries*: In 2019, extensions and discoveries in Lower 48 were due to planned development to add specific well locations from the unconventional plays which more than offset the decreases in the revisions category. Extensions and discoveries in our equity affiliates were due to ongoing development in APLNG.

  In 2018, extensions and discoveries in Lower 48 were primarily due to changes in the development strategy to add specific well locations from the unconventional plays. Extensions and discoveries in Canada, Europe and our equity affiliates in Asia Pacific/Middle East were primarily driven by ongoing drilling successes in Montney, Norway and APLNG, respectively.

  In 2017, extensions and discoveries in Lower 48 were primarily due to continued drilling success in the Permian Unconventional, Eagle Ford and Bakken.

- *Sales*: In 2019, Europe sales represent the disposition of the U.K. assets. In 2018, Lower 48 sales were primarily due to the disposition of our interest in Barnett. In 2017, Lower 48 sales were due to the disposition of our interests in the San Juan Basin and Panhandle assets, while Canada sales were due to the disposition of a majority of our western Canada assets.

Years Ended December 31	Bitumen
	Millions of Barrels
	Canada
Developed and Undeveloped	
Consolidated operations	
End of 2016	159
Revisions	16
Improved recovery	-
Purchases	-
Extensions and discoveries	96
Production	(21)
Sales	-
End of 2017	250
Revisions	10
Improved recovery	-
Purchases	-
Extensions and discoveries	-
Production	(24)
Sales	-
End of 2018	236
Revisions	37
Improved recovery	-
Purchases	-
Extensions and discoveries	31
Production	(22)
Sales	-
End of 2019	282
Equity affiliates	
End of 2016	1,089
Revisions	-
Improved recovery	-
Purchases	-
Extensions and discoveries	-
Production	(23)
Sales	(1,066)
End of 2017	-
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	
Sales	
End of 2018	
Revisions	
Improved recovery	
Purchases	
Extensions and discoveries	
Production	
Sales	
End of 2019	
Total company	
End of 2016	1,248
End of 2017	250
End of 2018	236
End of 2019	282

Years Ended December 31	Bitumen Millions of Barrels Canada
Developed	
Consolidated operations	
End of 2016	159
End of 2017	154
End of 2018	155
End of 2019	187
Equity affiliates	
End of 2016	322
End of 2017	-
End of 2018	-
End of 2019	-
Undeveloped	
Consolidated operations	
End of 2016	-
End of 2017	96
End of 2018	81
End of 2019	95
Equity affiliates	
End of 2016	767
End of 2017	-
End of 2018	-
End of 2019	-

Notable changes in proved bitumen reserves in the three years ended December 31, 2019, included:

- *Revisions*: In 2019, upward revisions in Canada were due to technical revisions in Surmont of 70 million barrels, partially offset by downward revisions due to changes in development timing for specific pad locations from the Surmont development program of 31 million barrels.

  In 2018 and 2017, revisions were primarily due to higher prices at Surmont.

- *Extensions and discoveries*: In 2019, extensions and discoveries in Canada were due to planned development to add specific pad locations from the Surmont development program, which offset the decrease in the revisions category of 31 million barrels.

  In 2017, extensions and discoveries were primarily due to higher prices at Surmont, which allowed undeveloped reserves previously de-booked due to low prices to be recognized.

- *Sales*: In 2017, sales were due to the disposition of our 50 percent interest in the FCCL Partnership in Canada.

Years Ended December 31	Total Proved Reserves							
	Millions of Barrels of Oil Equivalent							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed and Undeveloped								
Consolidated operations								
End of 2016	1,294	1,570	2,864	393	528	444	241	4,470
Revisions	166	170	336	18	68	36	-	458
Improved recovery	6	-	6	-	-	-	-	6
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	41	378	419	97	-	7	-	523
Production	(77)	(144)	(221)	(37)	(79)	(81)	(8)	(426)
Sales	-	(621)	(621)	(217)	-	-	-	(838)
End of 2017	1,430	1,353	2,783	254	517	406	233	4,193
Revisions	102	(161)	(59)	12	40	5	6	4
Improved recovery	2	-	2	-	-	-	-	2
Purchases	289	1	290	-	-	-	-	290
Extensions and discoveries	48	335	383	4	21	6	-	414
Production	(76)	(146)	(222)	(25)	(75)	(75)	(15)	(412)
Sales	-	(70)	(70)	-	(38)	-	-	(108)
End of 2018	1,795	1,312	3,107	245	465	342	224	4,383
Revisions	44	(67)	(23)	36	48	19	26	106
Improved recovery	7	-	7	-	-	-	-	7
Purchases	-	2	2	-	-	-	-	2
Extensions and discoveries	26	368	394	38	-	11	-	443
Production	(93)	(165)	(258)	(23)	(68)	(74)	(16)	(439)
Sales	-	(3)	(3)	-	(85)	-	-	(88)
End of 2019	1,779	1,447	3,226	296	360	298	234	4,414
Equity affiliates								
End of 2016	-	-	-	1,089	-	865	-	1,954
Revisions	-	-	-	-	-	18	-	18
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	31	-	31
Production	-	-	-	(23)	-	(69)	-	(92)
Sales	-	-	-	(1,066)	-	-	-	(1,066)
End of 2017	-	-	-	-	-	845	-	845
Revisions	-	-	-	-	-	46	-	46
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	60	-	60
Production	-	-	-	-	-	(71)	-	(71)
Sales	-	-	-	-	-	-	-	-
End of 2018	-	-	-	-	-	880	-	880
Revisions	-	-	-	-	-	(1)	-	(1)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	42	-	42
Production	-	-	-	-	-	(73)	-	(73)
Sales	-	-	-	-	-	-	-	-
End of 2019	-	-	-	-	-	848	-	848
Total company								
End of 2016	1,294	1,570	2,864	1,482	528	1,309	241	6,424
End of 2017	1,430	1,353	2,783	254	517	1,251	233	5,038
End of 2018	1,795	1,312	3,107	245	465	1,222	224	5,263
End of 2019	1,779	1,447	3,226	296	360	1,146	234	5,262

Years Ended December 31	Total Proved Reserves							
	Millions of Barrels of Oil Equivalent							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
Developed								
Consolidated operations								
End of 2016	1,203	1,165	2,368	391	365	309	241	3,674
End of 2017	1,319	682	2,001	158	372	281	233	3,045
End of 2018	1,617	681	2,298	160	382	244	221	3,305
End of 2019	1,582	666	2,248	197	275	236	218	3,174
Equity affiliates								
End of 2016	-	-	-	322	-	820	-	1,142
End of 2017	-	-	-	-	-	802	-	802
End of 2018	-	-	-	-	-	796	-	796
End of 2019	-	-	-	-	-	761	-	761
Undeveloped								
Consolidated operations								
End of 2016	91	405	496	2	163	135	-	796
End of 2017	111	671	782	96	145	125	-	1,148
End of 2018	178	631	809	85	83	98	3	1,078
End of 2019	197	781	978	99	85	62	16	1,240
Equity affiliates								
End of 2016	-	-	-	767	-	45	-	812
End of 2017	-	-	-	-	-	43	-	43
End of 2018	-	-	-	-	-	84	-	84
End of 2019	-	-	-	-	-	87	-	87

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six MCF of natural gas converts to one BOE.

Proved Undeveloped Reserves

We had 1,327 MMBOE of PUDs at year-end 2019, compared with 1,162 MMBOE at year-end 2018. The following table shows changes in total proved undeveloped reserves for 2019:

	Proved Undeveloped Reserves Millions of Barrels of Oil Equivalent
End of 2018	1,162
Transfers to proved developed	(286)
Revisions	(5)
Improved recovery	7
Purchases	1
Extensions and discoveries	468
Sales	(20)
End of 2019	1,327

Transfers to proved developed reserves were driven by the ongoing development of our assets. Approximately half of the transfers were from the development of our Lower 48 unconventional plays. The remainder of transfers were from development across the Asia Pacific/Middle East, Alaska, Europe and Canada regions.

Downward revisions were driven by changes in development timing of 166 MMBOE primarily in Lower 48 and Canada, largely offset by upward revisions for infill drilling of 147 MMBOE primarily in Lower 48, Europe, Alaska and Africa.

Extensions and discoveries were largely driven by an addition of 358 MMBOE in Lower 48 for the continued development of unconventional plays. The remaining extensions and discoveries were driven by the continued development planned in Alaska, Canada and Asia Pacific/Middle East.

Sales were due to the disposition of the U.K. assets.

At December 31, 2019, our PUDs represented 25 percent of total proved reserves, compared with 22 percent at December 31, 2018. Costs incurred for the year ended December 31, 2019, relating to the development of PUDs were $4.6 billion. A portion of our costs incurred each year relates to development projects where the PUDs will be converted to proved developed reserves in future years.

At the end of 2019, more than 90 percent of total PUDs were under development or scheduled for development within five years of initial disclosure. The remainder are to be developed as parts of major projects ongoing in our Canada, Asia Pacific/Middle East and Europe regions. All major development areas are currently producing and are expected to have PUDs convert to proved developed over time. Of our total PUDs at year-end 2019, 81 percent are in North America, and 95 percent of these reserve volumes are planned for development within five years of initial disclosure.

Results of Operations

The company's results of operations from oil and gas activities for the years 2019, 2018 and 2017 are shown in the following tables. Non-oil and gas activities, such as pipeline and marine operations, LNG operations, crude oil and gas marketing activities, and the profit element of transportation operations in which we have an ownership interest are excluded. Additional information about selected line items within the results of operations tables is shown below:

- Sales include sales to unaffiliated entities attributable primarily to the company's net working interests and royalty interests. Sales are net of fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are not consolidated.

- Transportation costs reflect fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are consolidated.

- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.

- Production costs include costs incurred to operate and maintain wells, related equipment and facilities used in the production of petroleum liquids and natural gas.

- Taxes other than income taxes include production, property and other non-income taxes.

- Depreciation of support equipment is reclassified as applicable.

- Other related expenses include inventory fluctuations, foreign currency transaction gains and losses and other miscellaneous expenses.

Results of Operations

Year Ended December 31, 2019	Millions of Dollars									
		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations										
Sales	$	4,883	6,356	11,239	709	3,207	3,032	919	-	19,106
Transfers		4	-	4	-	-	449	-	-	453
Transportation costs		(629)	-	(629)	-	-	(41)	-	-	(670)
Other revenues		61	78	139	86	1,785	12	101	326	2,449
Total revenues		4,319	6,434	10,753	795	4,992	3,452	1,020	326	21,338
Production costs excluding taxes		1,235	1,578	2,813	380	741	619	70	(8)	4,615
Taxes other than income taxes		308	437	745	18	32	54	3	(2)	850
Exploration expenses		97	430	527	32	69	80	5	33	746
Depreciation, depletion and amortization		700	2,804	3,504	230	842	1,172	37	-	5,785
Impairments		-	402	402	2	1	-	-	-	405
Other related expenses		(12)	116	104	(38)	(42)	58	22	10	114
Accretion		62	49	111	7	142	43	-	-	303
		1,929	618	2,547	164	3,207	1,426	883	293	8,520
Income tax provision (benefit)		444	147	591	(74)	591	458	833	7	2,406
Results of operations	$	1,485	471	1,956	238	2,616	968	50	286	6,114
Equity affiliates										
Sales	$	-	-	-	-	-	599	-	-	599
Transfers		-	-	-	-	-	2,229	-	-	2,229
Transportation costs		-	-	-	-	-	-	-	-	-
Other revenues		-	-	-	-	-	31	-	-	31
Total revenues		-	-	-	-	-	2,859	-	-	2,859
Production costs excluding taxes		-	-	-	-	-	335	-	-	335
Taxes other than income taxes		-	-	-	-	-	820	-	-	820
Exploration expenses		-	-	-	-	-	-	-	-	-
Depreciation, depletion and amortization		-	-	-	-	-	579	-	-	579
Impairments		-	-	-	-	-	-	-	-	-
Other related expenses		-	-	-	-	-	11	-	-	11
Accretion		-	-	-	-	-	16	-	-	16
		-	-	-	-	-	1,098	-	-	1,098
Income tax provision (benefit)		-	-	-	-	-	170	-	-	170
Results of operations	$	-	-	-	-	-	928	-	-	928

Year Ended December 31, 2018		Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations									
Sales	$ 4,816	6,573	11,389	582	4,449	3,177	950	-	20,547
Transfers	5	-	5	-	-	545	-	-	550
Transportation costs	(722)	-	(722)	-	-	(45)	-	-	(767)
Other revenues	335	213	548	164	737	6	110	432	1,997
Total revenues	4,434	6,786	11,220	746	5,186	3,683	1,060	432	22,327
Production costs excluding taxes	964	1,533	2,497	417	856	646	62	2	4,480
Taxes other than income taxes	357	432	789	21	33	95	3	-	941
Exploration expenses	59	176	235	21	57	43	(4)	20	372
Depreciation, depletion and amortization	616	2,279	2,895	313	1,070	1,186	33	-	5,497
Impairments	1	64	65	9	(78)	14	-	-	10
Other related expenses	16	63	79	56	(62)	(19)	1	(1)	54
Accretion	56	51	107	7	178	39	-	-	331
	2,365	2,188	4,553	(98)	3,132	1,679	965	411	10,642
Income tax provision (benefit)	419	466	885	(114)	1,354	683	926	(8)	3,726
Results of operations	$ 1,946	1,722	3,668	16	1,778	996	39	419	6,916
Equity affiliates									
Sales	$ -	-	-	-	-	758	-	-	758
Transfers	-	-	-	-	-	2,018	-	-	2,018
Transportation costs	-	-	-	-	-	-	-	-	-
Other revenues	-	-	-	-	-	(6)	-	-	(6)
Total revenues	-	-	-	-	-	2,770	-	-	2,770
Production costs excluding taxes	-	-	-	-	-	321	-	-	321
Taxes other than income taxes	-	-	-	-	-	804	-	-	804
Exploration expenses	-	-	-	-	-	-	-	-	-
Depreciation, depletion and amortization	-	-	-	-	-	640	-	-	640
Impairments	-	-	-	-	-	-	-	-	-
Other related expenses	-	-	-	-	-	(4)	-	-	(4)
Accretion	-	-	-	-	-	15	-	-	15
	-	-	-	-	-	994	-	-	994
Income tax provision (benefit)	-	-	-	-	-	103	-	-	103
Results of operations	$ -	-	-	-	-	891	-	-	891

Year Ended December 31, 2017	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations									
Sales	$ 3,542	4,557	8,099	705	3,527	2,752	487	-	15,570
Transfers	4	-	4	-	-	411	-	-	415
Transportation costs	(706)	-	(706)	-	-	(80)	-	-	(786)
Other revenues	14	28	42	2,158	68	11	48	322	2,649
Total revenues	2,854	4,585	7,439	2,863	3,595	3,094	535	322	17,848
Production costs excluding taxes	947	1,607	2,554	604	770	566	44	(1)	4,537
Taxes other than income taxes	275	318	593	33	32	39	2	-	699
Exploration expenses	83	584	667	22	45	97	61	45	937
Depreciation, depletion and									
amortization	730	2,685	3,415	438	1,234	1,283	16	-	6,386
Impairments	179	3,969	4,148	22	46	-	-	-	4,216
Other related expenses	(7)	62	55	7	57	60	6	-	185
Accretion	52	63	115	16	172	37	-	-	340
	595	(4,703)	(4,108)	1,721	1,239	1,012	406	278	548
Income tax provision (benefit)	(669)	(2,401)	(3,070)	(651)	702	363	428	11	(2,217)
Results of operations	$ 1,264	(2,302)	(1,038)	2,372	537	649	(22)	267	2,765
Equity affiliates									
Sales	$ -	-	-	528	-	563	-	-	1,091
Transfers	-	-	-	-	-	1,398	-	-	1,398
Transportation costs	-	-	-	-	-	-	-	-	-
Other revenues	-	-	-	5	-	-	-	-	5
Total revenues	-	-	-	533	-	1,961	-	-	2,494
Production costs excluding taxes	-	-	-	174	-	363	-	-	537
Taxes other than income taxes	-	-	-	7	-	604	-	-	611
Exploration expenses	-	-	-	1	-	1,699	-	-	1,700
Depreciation, depletion and	-	-	-	-	-	-	-	-	
amortization	-	-	-	150	-	617	-	-	767
Impairments	-	-	-	-	-	1,717	-	-	1,717
Other related expenses	-	-	-	4	-	22	-	19	45
Accretion	-	-	-	2	-	11	-	-	13
	-	-	-	195	-	(3,072)	-	(19)	(2,896)
Income tax provision (benefit)	-	-	-	26	-	(998)	-	13	(959)
Results of operations	$ -	-	-	169	-	(2,074)	-	(32)	(1,937)

Statistics

Net Production	2019	2018	2017
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**202**	171	167
Lower 48	**266**	229	180
United States	**468**	400	347
Canada	**1**	1	3
Europe	**100**	113	122
Asia Pacific/Middle East	**85**	89	93
Africa	**38**	36	20
Total consolidated operations	**692**	639	585
Equity affiliates—Asia Pacific/Middle East	**13**	14	14
Total company	**705**	653	599
*Greater Prudhoe Area (Alaska)**	***66***	*71*	*74*
Natural Gas Liquids			
Consolidated operations			
Alaska	**15**	14	14
Lower 48	**81**	69	69
United States	**96**	83	83
Canada	**-**	1	9
Europe	**7**	8	8
Asia Pacific/Middle East	**4**	3	4
Total consolidated operations	**107**	95	104
Equity affiliates—Asia Pacific/Middle East	**8**	7	7
Total company	**115**	102	111
*Greater Prudhoe Area (Alaska)**	***15***	*14*	*14*
Bitumen			
Consolidated operations—Canada	**60**	66	59
Equity affiliates—Canada			63
Total company	**60**	66	122
Natural Gas	Millions of Cubic Feet Daily		
Consolidated operations			
Alaska	**7**	6	7
Lower 48	**622**	596	898
United States	**629**	602	905
Canada	**9**	12	187
Europe	**447**	475	476
Asia Pacific/Middle East	**637**	626	687
Africa	**31**	28	8
Total consolidated operations	**1,753**	1,743	2,263
Equity affiliates—Asia Pacific/Middle East	**1,052**	1,031	1,007
Total company	**2,805**	2,774	3,270
*Greater Prudhoe Area (Alaska)**	***4***	*5*	*5*

**At year-end 2019, the Greater Prudhoe Area in Alaska contained more than 15% of total proved reserves.*

Average Sales Prices		2019	2018	2017
Crude Oil Per Barrel				
Consolidated operations				
Alaska	$	**55.85**	60.23	42.69
Lower 48		**55.30**	62.99	47.36
United States		**55.54**	61.75	45.01
Canada		**40.87**	48.73	43.69
Europe		**65.12**	70.98	54.04
Asia Pacific/Middle East		**65.02**	70.93	54.38
Africa		**64.47**	69.83	55.11
Total international		**64.85**	70.67	54.16
Total consolidated operations		**58.51**	65.01	48.70
Equity affiliates—Asia Pacific/Middle East		**61.32**	72.49	54.76
Total operations		**58.57**	65.17	48.84
Natural Gas Liquids Per Barrel				
Consolidated operations				
Lower 48	$	**16.83**	27.30	22.20
United States		**16.85**	27.30	22.20
Canada		**19.87**	43.70	21.51
Europe		**29.37**	36.87	34.07
Asia Pacific/Middle East		**37.85**	47.20	41.37
Total international		**32.29**	40.00	30.34
Total consolidated operations		**18.73**	29.03	24.21
Equity affiliates—Asia Pacific/Middle East		**36.70**	45.69	38.74
Total operations		**20.09**	30.48	25.22
Bitumen Per Barrel				
Consolidated operations—Canada	$	**31.72**	22.29	21.43
Equity affiliates—Canada				23.83
Natural Gas Per Thousand Cubic Feet				
Consolidated operations				
Alaska	$	**3.19**	2.48	2.72
Lower 48		**2.12**	2.82	2.73
United States		**2.12**	2.82	2.73
Canada		**0.49**	1.00	1.93
Europe		**4.92**	7.79	5.72
Asia Pacific/Middle East		**5.73**	5.95	4.66
Africa		**4.87**	4.84	3.53
Total international		**5.35**	6.64	4.64
Total consolidated operations		**4.19**	5.33	3.87
Equity affiliates—Asia Pacific/Middle East		**6.29**	6.06	4.27
Total operations		**4.99**	5.60	4.00

Average sales prices for Alaska crude oil and Asia Pacific/Middle East natural gas above reflect a reduction for transportation costs in which we have an ownership interest that are incurred subsequent to the terminal point of the production function. Accordingly, the average sales prices differ from those discussed in Item 7 of Management's Discussion and Analysis of Financial Condition and Results of Operations.

		2019	2018	2017
Average Production Costs Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**15.52**	14.20	14.26
Lower 48		**9.59**	10.58	11.03
United States		**11.52**	11.73	12.04
Canada		**16.53**	16.32	16.22
Europe		**11.22**	11.73	10.09
Asia Pacific/Middle East		**8.74**	9.03	7.31
Africa		**4.46**	4.14	5.74
Total international		**10.26**	10.72	9.99
Total consolidated operations		**10.99**	11.26	11.05
Equity affiliates				
Canada				7.57
Asia Pacific/Middle East		**4.68**	4.56	5.26
Total equity affiliates		**4.68**	4.56	5.84
Average Production Costs Per Barrel—Bitumen				
Consolidated operations—Canada	$	**13.74**	13.59	14.63
Equity affiliates—Canada				18.74
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**3.87**	5.26	4.14
Lower 48		**2.65**	2.98	2.18
United States		**3.05**	3.71	2.80
Canada		**0.78**	0.82	0.89
Europe		**0.48**	0.45	0.42
Asia Pacific/Middle East		**0.76**	1.33	0.50
Africa		**0.19**	0.20	0.26
Total international		**0.60**	0.82	0.53
Total consolidated operations		**2.03**	2.37	1.70
Equity affiliates				
Canada				0.30
Asia Pacific/Middle East		**11.46**	11.41	8.76
Total equity affiliates		**11.46**	11.41	6.64
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**8.80**	9.07	10.99
Lower 48		**17.03**	15.73	18.44
United States		**14.35**	13.60	16.10
Canada		**10.00**	12.25	11.76
Europe		**12.75**	14.66	16.18
Asia Pacific/Middle East		**16.55**	16.58	16.58
Africa		**2.36**	2.21	2.09
Total international		**12.99**	14.06	14.96
Total consolidated operations		**13.78**	13.82	15.55
Equity affiliates				
Canada				6.52
Asia Pacific/Middle East		**8.09**	9.09	8.94
Total equity affiliates		**8.09**	9.09	8.34

**Includes bitumen.*

Development and Exploration Activities

The following two tables summarize our net interest in productive and dry exploratory and development wells in the years ended December 31, 2019, 2018 and 2017. A "development well" is a well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive. An "exploratory well" is a well drilled to find and produce crude oil or natural gas in an unknown field or a new reservoir within a proven field. Exploratory wells also include wells drilled in areas near or offsetting current production, or in areas where well density or production history have not achieved statistical certainty of results. Excluded from the exploratory well count are stratigraphic-type exploratory wells, primarily relating to oil sands delineation wells located in Canada and CBM test wells located in Asia Pacific/Middle East.

Net Wells Completed	Productive			Dry		
	2019	2018	2017	**2019**	2018	2017
Exploratory						
Consolidated operations						
Alaska	**7**	6	-	-	-	-
Lower 48	**35**	45	13	**6**	1	3
United States	**42**	51	13	**6**	1	3
Canada	-	2	13	-	-	-
Europe	**1**	*	*	**1**	*	*
Asia Pacific/Middle East	**1**	2	1	**1**	-	1
Africa	-	-	-	-	*	-
Other areas	-	-	-	-	-	1
Total consolidated operations	**44**	55	27	**8**	1	5
Equity affiliates						
Asia Pacific/Middle East	**8**	6	14	-	2	-
Total equity affiliates	**8**	6	14	-	2	-
Development						
Consolidated operations						
Alaska	**12**	11	9	-	-	-
Lower 48	**255**	254	161	-	-	-
United States	**267**	265	170	-	-	-
Canada	**2**	1	13	-	-	-
Europe	**6**	9	7	-	-	-
Asia Pacific/Middle East	**21**	12	8	-	-	-
Africa	**2**	1	-	-	-	-
Other areas	-	-	-	-	-	-
Total consolidated operations	**298**	288	198	-	-	-
Equity affiliates						
Canada	-	-	19	-	-	-
Asia Pacific/Middle East	**106**	75	84	-	-	-
Other areas	-	-	-	-	-	-
Total equity affiliates	**106**	75	103	-	-	-

**Our total proportionate interest was less than one.*

The table below represents the status of our wells drilling at December 31, 2019, and includes wells in the process of drilling or in active completion. It also represents gross and net productive wells, including producing wells and wells capable of production at December 31, 2019.

Wells at December 31, 2019			Productive			
	In Progress		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	4	4	1,656	997	-	-
Lower 48	349	170	10,070	4,547	4,329	1,704
United States	353	174	11,726	5,544	4,329	1,704
Canada	32	32	186	93	31	27
Europe	19	1	469	79	55	2
Asia Pacific/Middle East	12	6	302	143	56	28
Africa	13	2	840	137	7	1
Other areas	14	7	-	-	-	-
Total consolidated operations	443	222	13,523	5,996	4,478	1,762
Equity affiliates						
Asia Pacific/Middle East	325	79	-	-	4,307	1,051
Total equity affiliates	325	79	-	-	4,307	1,051

Acreage at December 31, 2019	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	651	467	1,331	1,320
Lower 48	2,569	2,012	10,337	8,396
United States	3,220	2,479	11,668	9,716
Canada	206	126	3,270	1,798
Europe	430	50	2,102	610
Asia Pacific/Middle East	1,538	721	9,910	5,735
Africa	358	58	12,545	2,049
Other areas	-	-	1,400	742
Total consolidated operations	5,752	3,434	40,895	20,650
Equity affiliates				
Asia Pacific/Middle East	933	229	3,723	840
Total equity affiliates	933	229	3,723	840

Costs Incurred

Year Ended December 31		Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
		Millions of Dollars								
2019										
Consolidated operations										
Unproved property acquisition	$	101	45	146	14	-	-	-	197	357
Proved property acquisition		1	116	117	-	-	115	-	-	232
		102	161	263	14	-	115	-	197	589
Exploration		281	390	671	200	119	66	8	39	1,103
Development		1,125	3,028	4,153	215	625	486	22	-	5,501
	$	1,508	3,579	5,087	429	744	667	30	236	7,193
Equity affiliates										
Unproved property acquisition	$	-	-	-	-	-	62	-	-	62
Proved property acquisition		-	-	-	-	-	-	-	-	-
		-	-	-	-	-	62	-	-	62
Exploration		-	-	-	-	-	23	-	-	23
Development		-	-	-	-	-	171	-	-	171
	$	-	-	-	-	-	256	-	-	256
2018										
Consolidated operations										
Unproved property acquisition	$	119	126	245	126	-	-	-	-	371
Proved property acquisition		2,227	16	2,243	6	-	-	-	-	2,249
		2,346	142	2,488	132	-	-	-	-	2,620
Exploration		203	500	703	90	65	82	(6)	41	975
Development		718	2,715	3,433	301	703	773	16	-	5,226
	$	3,267	3,357	6,624	523	768	855	10	41	8,821
Equity affiliates										
Unproved property acquisition	$	-	-	-	-	-	-	-	-	-
Proved property acquisition		-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-
Exploration		-	-	-	-	-	22	-	-	22
Development		-	-	-	-	-	206	-	-	206
	$	-	-	-	-	-	228	-	-	228
2017										
Consolidated operations										
Unproved property acquisition	$	18	267	285	76	-	15	-	-	376
Proved property acquisition		-	35	35	-	-	-	-	-	35
		18	302	320	76	-	15	-	-	411
Exploration		74	399	473	56	52	139	61	42	823
Development		736	1,559	2,295	102	784	388	10	-	3,579
	$	828	2,260	3,088	234	836	542	71	42	4,813
Equity affiliates										
Unproved property acquisition	$	-	-	-	-	-	-	-	-	-
Proved property acquisition		-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-
Exploration		-	-	-	6	-	38	-	-	44
Development		-	-	-	150	-	403	-	-	553
	$	-	-	-	156	-	441	-	-	597

Capitalized Costs

At December 31	Millions of Dollars								
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total
2019									
Consolidated operations									
Proved property	$ 20,957	37,491	58,448	6,673	14,113	14,566	924	-	94,724
Unproved property	1,429	1,055	2,484	1,149	87	501	123	290	4,634
	22,386	38,546	60,932	7,822	14,200	15,067	1,047	290	99,358
Accumulated depreciation, depletion and amortization	9,419	26,294	35,713	2,050	9,017	10,253	379	9	57,421
	$ 12,967	12,252	25,219	5,772	5,183	4,814	668	281	41,937
Equity affiliates									
Proved property	$ -	-	-	-	-	9,996	-	-	9,996
Unproved property	-	-	-	-	-	2,223	-	-	2,223
	-	-	-	-	-	12,219	-	-	12,219
Accumulated depreciation, depletion and amortization	-	-	-	-	-	6,390	-	-	6,390
	$ -	-	-	-	-	5,829	-	-	5,829
2018									
Consolidated operations									
Proved property	$ 20,154	35,269	55,423	5,946	23,520	14,866	902	-	100,657
Unproved property	1,184	1,125	2,309	1,083	188	874	119	89	4,662
	21,338	36,394	57,732	7,029	23,708	15,740	1,021	89	105,319
Accumulated depreciation, depletion and amortization	9,055	23,999	33,054	1,692	16,591	9,974	342	9	61,662
	$ 12,283	12,395	24,678	5,337	7,117	5,766	679	80	43,657
Equity affiliates									
Proved property	$ -	-	-	-	-	9,990	-	-	9,990
Unproved property	-	-	-	-	-	2,162	-	-	2,162
	-	-	-	-	-	12,152	-	-	12,152
Accumulated depreciation, depletion and amortization	-	-	-	-	-	5,960	-	-	5,960
	$ -	-	-	-	-	6,192	-	-	6,192

<u>Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities</u>

In accordance with SEC and FASB requirements, amounts were computed using 12-month average prices (adjusted only for existing contractual terms) and end-of-year costs, appropriate statutory tax rates and a prescribed 10 percent discount factor. Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. For all years, continuation of year-end economic conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, were not considered. The calculations also require assumptions as to the timing of future production of proved reserves and the timing and amount of future development costs, including dismantlement, and future production costs, including taxes other than income taxes.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Discounted Future Net Cash Flows

	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
2019								
Consolidated operations								
Future cash inflows	$ 70,341	53,400	123,741	8,244	16,919	13,084	15,582	177,570
Less:								
Future production costs	40,464	22,194	62,658	4,525	5,843	5,162	1,314	79,502
Future development costs	9,721	14,083	23,804	577	4,143	2,179	484	31,187
Future income tax provisions	3,904	2,793	6,697	-	4,201	1,931	12,747	25,576
Future net cash flows	16,252	14,330	30,582	3,142	2,732	3,812	1,037	41,305
10 percent annual discount	6,571	4,311	10,882	1,198	558	835	460	13,933
Discounted future net cash flows	$ 9,681	10,019	19,700	1,944	2,174	2,977	577	27,372
Equity affiliates								
Future cash inflows	$ -	-	-	-	-	31,671	-	31,671
Less:								
Future production costs	-	-	-	-	-	16,157	-	16,157
Future development costs	-	-	-	-	-	1,218	-	1,218
Future income tax provisions	-	-	-	-	-	3,086	-	3,086
Future net cash flows	-	-	-	-	-	11,210	-	11,210
10 percent annual discount	-	-	-	-	-	4,040	-	4,040
Discounted future net cash flows	$ -	-	-	-	-	7,170	-	7,170
Total company								
Discounted future net cash flows	$ 9,681	10,019	19,700	1,944	2,174	10,147	577	34,542

	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
2018								
Consolidated operations								
Future cash inflows	$ 82,072	56,922	138,994	6,039	26,989	16,368	16,434	204,824
Less:								
Future production costs	42,755	21,363	64,118	4,099	8,567	5,705	1,336	83,825
Future development costs	10,053	12,136	22,189	606	7,608	1,995	507	32,905
Future income tax provisions	5,538	4,418	9,956	-	7,102	2,873	13,492	33,423
Future net cash flows	23,726	19,005	42,731	1,334	3,712	5,795	1,099	54,671
10 percent annual discount	10,349	6,461	16,810	426	371	1,132	498	19,237
Discounted future net cash flows	$ 13,377	12,544	25,921	908	3,341	4,663	601	35,434
Equity affiliates								
Future cash inflows	$ -	-	-	-	-	33,606	-	33,606
Less:								
Future production costs	-	-	-	-	-	16,449	-	16,449
Future development costs	-	-	-	-	-	1,228	-	1,228
Future income tax provisions	-	-	-	-	-	3,147	-	3,147
Future net cash flows	-	-	-	-	-	12,782	-	12,782
10 percent annual discount	-	-	-	-	-	4,853	-	4,853
Discounted future net cash flows	$ -	-	-	-	-	7,929	-	7,929
Total company								
Discounted future net cash flows	$ 13,377	12,544	25,921	908	3,341	12,592	601	43,363

	Millions of Dollars							
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total
2017								
Consolidated operations								
Future cash inflows	$ 44,969	44,556	89,525	5,479	23,137	15,207	13,181	146,529
Less:								
Future production costs	29,524	18,947	48,471	4,417	8,128	5,398	1,401	67,815
Future development costs	7,255	10,881	18,136	696	8,758	2,511	537	30,638
Future income tax provisions	53	2,375	2,428	-	3,333	2,459	10,356	18,576
Future net cash flows	8,137	12,353	20,490	366	2,918	4,839	887	29,500
10 percent annual discount	2,712	4,358	7,070	78	289	1,032	422	8,891
Discounted future net cash flows	$ 5,425	7,995	13,420	288	2,629	3,807	465	20,609
Equity affiliates								
Future cash inflows	$ -	-	-	-	-	23,222	-	23,222
Less:								
Future production costs	-	-	-	-	-	12,984	-	12,984
Future development costs	-	-	-	-	-	1,444	-	1,444
Future income tax provisions	-	-	-	-	-	2,083	-	2,083
Future net cash flows	-	-	-	-	-	6,711	-	6,711
10 percent annual discount	-	-	-	-	-	2,316	-	2,316
Discounted future net cash flows	$ -	-	-	-	-	4,395	-	4,395
Total company								
Discounted future net cash flows	$ 5,425	7,995	13,420	288	2,629	8,202	465	25,004

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2019	2018	2017	**2019**	2018	2017	**2019**	2018	2017
Discounted future net cash flows at the beginning of the year	$ **35,434**	20,609	8,151	**7,929**	4,395	3,937	**43,363**	25,004	12,088
Changes during the year									
Revenues less production costs for the year	**(13,424)**	(14,909)	(9,844)	**(1,673)**	(1,651)	(1,341)	**(15,097)**	(16,560)	(11,185)
Net change in prices and production costs	**(13,538)**	25,391	19,310	**(422)**	4,559	2,750	**(13,960)**	29,950	22,060
Extensions, discoveries and improved recovery, less estimated future costs	**2,985**	4,574	1,445	**260**	382	(4)	**3,245**	4,956	1,441
Development costs for the year	**5,333**	5,197	3,653	**239**	271	426	**5,572**	5,468	4,079
Changes in estimated future development costs	**559**	(1,141)	1,225	**(21)**	14	(64)	**538**	(1,127)	1,161
Purchases of reserves in place, less estimated future costs	**10**	3,033	-	**-**	-	-	**10**	3,033	-
Sales of reserves in place, less estimated future costs	**(1,997)**	(1,531)	(855)	**-**	-	(786)	**(1,997)**	(1,531)	(1,641)
Revisions of previous quantity estimates	**2,099**	(365)	2,300	**69**	62	(648)	**2,168**	(303)	1,652
Accretion of discount	**5,144**	3,055	1,313	**869**	485	413	**6,013**	3,540	1,726
Net change in income taxes	**4,767**	(8,479)	(6,089)	**(80)**	(588)	(288)	**4,687**	(9,067)	(6,377)
Total changes	**(8,062)**	14,825	12,458	**(759)**	3,534	458	**(8,821)**	18,359	12,916
Discounted future net cash flows at year end	$ **27,372**	35,434	20,609	**7,170**	7,929	4,395	**34,542**	43,363	25,004

- The net change in prices and production costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price and production cost, discounted at 10 percent.

- Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

- Revisions of previous quantity estimates are calculated using production forecast changes for the year, including changes in the timing of production, multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production and development costs.

- The net change in income taxes is the annual change in the discounted future income tax provisions.

Selected Quarterly Financial Data (Unaudited)

	Millions of Dollars				Per Share of Common Stock	
					Net Income (Loss) Attributable to ConocoPhillips	
	Sales and Other Operating Revenues	Income (Loss) Before Income Taxes	Net Income (Loss)	Net Income (Loss) Attributable to ConocoPhillips	Basic	Diluted
2019						
First	$ **9,150**	**2,687**	**1,846**	**1,833**	**1.61**	**1.60**
Second	**7,953**	**2,058**	**1,597**	**1,580**	**1.40**	**1.40**
Third	**7,756**	**3,493**	**3,071**	**3,056**	**2.76**	**2.74**
Fourth	**7,708**	**1,286**	**743**	**720**	**0.66**	**0.66**
2018						
First	$ 8,798	1,776	900	888	0.75	0.75
Second	8,504	2,619	1,654	1,640	1.40	1.39
Third	9,449	2,906	1,873	1,861	1.60	1.59
Fourth	9,666	2,672	1,878	1,868	1.62	1.61

For additional information on the commodity price environment, see the Business Environment and Executive Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations.

Supplementary Information—Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company and Burlington Resources LLC, with respect to publicly held debt securities. ConocoPhillips Company is 100 percent owned by ConocoPhillips. Burlington Resources LLC is 100 percent owned by ConocoPhillips Company. ConocoPhillips and/or ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of Burlington Resources LLC, with respect to its publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Company and Burlington Resources LLC (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other nonguarantor subsidiaries of ConocoPhillips.
- The consolidating adjustments necessary to present ConocoPhillips' results on a consolidated basis.

In 2017, ConocoPhillips Company received a $9.8 billion return of capital and a $1.4 billion loan repayment from nonguarantor subsidiaries to settle certain accumulated intercompany balances. These transactions had no impact on our consolidated financial statements.

In 2017, ConocoPhillips received a $7.8 billion return of capital and a $0.2 billion return of earnings from ConocoPhillips Company to settle certain accumulated intercompany balances. These transactions had no impact on our consolidated financial statements.

In 2018, ConocoPhillips Company received a $4.8 billion return of earnings and a $2.4 billion loan repayment from nonguarantor subsidiaries to settle certain accumulated intercompany balances. These transactions had no impact on our consolidated financial statements.

In 2018, ConocoPhillips received a $3.5 billion return of capital and a $1.0 billion return of earnings from ConocoPhillips Company to settle certain accumulated intercompany balances. These transactions had no impact on our consolidated financial statements.

In 2019, ConocoPhillips received a $2.4 billion return of capital and a $1.7 billion return of earnings from ConocoPhillips Company to settle certain accumulated intercompany balances. This transaction had no impact on our consolidated financial statements.

In 2019, ConocoPhillips Company received a $4.5 billion return of earnings and a $4.2 billion return of capital from nonguarantor subsidiaries to settle certain accumulated intercompany balances. These transactions had no impact on our consolidated financial statements.

In 2019, Burlington Resources LLC received a $3.2 billion return of earnings from nonguarantor subsidiaries to settle certain accumulated intercompany balances. These transactions had no impact on our consolidated financial statements.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

Income Statement	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Year Ended December 31, 2019					
Revenues and Other Income						
Sales and other operating revenues	$ -	14,510	-	18,057	-	32,567
Equity in earnings of affiliates	7,419	5,281	1,610	775	(14,306)	779
Gain (loss) on dispositions	-	2,786	-	(820)	-	1,966
Other income	1	875	5	477	-	1,358
Intercompany revenues	-	113	40	5,542	(5,695)	-
Total Revenues and Other Income	7,420	23,565	1,655	24,031	(20,001)	36,670
Costs and Expenses						
Purchased commodities	-	12,838	-	4,038	(5,034)	11,842
Production and operating expenses	1	1,380	1	4,345	(405)	5,322
Selling, general and administrative expenses	9	421	-	131	(5)	556
Exploration expenses	-	422	-	321	-	743
Depreciation, depletion and amortization	-	596	-	5,494	-	6,090
Impairments	-	157	-	248	-	405
Taxes other than income taxes	-	139	-	814	-	953
Accretion on discounted liabilities	-	16	-	310	-	326
Interest and debt expense	283	544	133	69	(251)	778
Foreign currency transaction losses	-	21	-	45	-	66
Other expenses	-	60	-	5	-	65
Total Costs and Expenses	293	16,594	134	15,820	(5,695)	27,146
Income before income taxes	7,127	6,971	1,521	8,211	(14,306)	9,524
Income tax provision (benefit)	(62)	(448)	(46)	2,823	-	2,267
Net income	7,189	7,419	1,567	5,388	(14,306)	7,257
Less: net income attributable to noncontrolling interests	-	-	-	(68)	-	(68)
Net Income Attributable to ConocoPhillips	$ 7,189	7,419	1,567	5,320	(14,306)	7,189
Comprehensive Income Attributable to ConocoPhillips	$ 7,935	8,165	1,873	6,058	(16,096)	7,935

Income Statement	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Year Ended December 31, 2018					
Revenues and Other Income						
Sales and other operating revenues	$ -	16,113	-	20,304	-	36,417
Equity in earnings of affiliates	6,503	8,142	1,953	1,072	(16,596)	1,074
Gain on dispositions	-	239	-	824	-	1,063
Other income (loss)	-	(384)	-	557	-	173
Intercompany revenues	35	162	43	5,627	(5,867)	-
Total Revenues and Other Income	6,538	24,272	1,996	28,384	(22,463)	38,727
Costs and Expenses						
Purchased commodities	-	14,591	-	5,131	(5,428)	14,294
Production and operating expenses	-	1,023	4	4,245	(59)	5,213
Selling, general and administrative expenses	8	289	-	109	(5)	401
Exploration expenses	-	170	-	199	-	369
Depreciation, depletion and amortization	-	584	-	5,372	-	5,956
Impairments	-	(10)	-	37	-	27
Taxes other than income taxes	-	143	-	905	-	1,048
Accretion on discounted liabilities	-	17	-	336	-	353
Interest and debt expense	295	613	46	156	(375)	735
Foreign currency transaction (gains) losses	46	(12)	116	(167)	-	(17)
Other expenses	-	349	6	20	-	375
Total Costs and Expenses	349	17,757	172	16,343	(5,867)	28,754
Income before income taxes	6,189	6,515	1,824	12,041	(16,596)	9,973
Income tax provision (benefit)	(68)	12	(41)	3,765	-	3,668
Net income	6,257	6,503	1,865	8,276	(16,596)	6,305
Less: net income attributable to noncontrolling interests	-	-	-	(48)	-	(48)
Net Income Attributable to ConocoPhillips	$ 6,257	6,503	1,865	8,228	(16,596)	6,257
Comprehensive Income Attributable to ConocoPhillips	$ 5,654	5,900	1,364	7,961	(15,225)	5,654

See Notes to Consolidated Financial Statements.

Income Statement		ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
		Millions of Dollars					
		Year Ended December 31, 2017					
Revenues and Other Income							
Sales and other operating revenues	$	-	12,433	-	16,673	-	29,106
Equity in earnings (losses) of affiliates		(454)	2,047	886	770	(2,477)	772
Gain on dispositions		-	916	-	1,261	-	2,177
Other income		2	35	-	492	-	529
Intercompany revenues		48	291	13	3,369	(3,721)	-
Total Revenues and Other Income		(404)	15,722	899	22,565	(6,198)	32,584
Costs and Expenses							
Purchased commodities		-	11,145	-	4,580	(3,250)	12,475
Production and operating expenses		-	813	-	4,366	(17)	5,162
Selling, general and administrative expenses		9	342	-	82	(6)	427
Exploration expenses		-	542	-	392	-	934
Depreciation, depletion and amortization		-	855	-	5,990	-	6,845
Impairments		-	1,159	-	5,442	-	6,601
Taxes other than income taxes		-	140	1	668	-	809
Accretion on discounted liabilities		-	32	-	330	-	362
Interest and debt expense		420	664	52	410	(448)	1,098
Foreign currency transaction (gains) losses		(43)	11	(137)	204	-	35
Other expenses		267	190	-	(6)	-	451
Total Costs and Expenses		653	15,893	(84)	22,458	(3,721)	35,199
Income (Loss) before income taxes		(1,057)	(171)	983	107	(2,477)	(2,615)
Income tax provision (benefit)		(202)	283	(337)	(1,566)	-	(1,822)
Net income (loss)		(855)	(454)	1,320	1,673	(2,477)	(793)
Less: net income attributable to noncontrolling interests		-	-	-	(62)	-	(62)
Net Income (Loss) Attributable to ConocoPhillips	$	(855)	(454)	1,320	1,611	(2,477)	(855)
Comprehensive Income (Loss) Attributable to ConocoPhillips	$	(180)	221	1,672	2,275	(4,168)	(180)

See Notes to Consolidated Financial Statements.

	Millions of Dollars					
	At December 31, 2019					
Balance Sheet	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$ -	3,439	-	1,649	-	5,088
Short-term investments	-	2,670	-	358	-	3,028
Accounts and notes receivable	5	2,088	2	3,881	(2,575)	3,401
Investment in Cenovus Energy	-	2,111	-	-	-	2,111
Inventories	-	168	-	858	-	1,026
Prepaid expenses and other current assets	1	352	-	1,906	-	2,259
Total Current Assets	6	10,828	2	8,652	(2,575)	16,913
Investments, loans and long-term receivables*	34,076	44,969	11,662	15,612	(97,413)	8,906
Net properties, plants and equipment	-	3,552	-	38,717	-	42,269
Other assets	3	765	253	2,210	(805)	2,426
Total Assets	$ 34,085	60,114	11,917	65,191	(100,793)	70,514
Liabilities and Stockholders' Equity						
Accounts payable	$ -	2,670	21	3,084	(2,575)	3,200
Short-term debt	(3)	4	13	91	-	105
Accrued income and other taxes	-	79	-	951	-	1,030
Employee benefit obligations	-	508	-	155	-	663
Other accruals	84	408	35	1,518	-	2,045
Total Current Liabilities	81	3,669	69	5,799	(2,575)	7,043
Long-term debt	3,794	6,670	2,129	2,197	-	14,790
Asset retirement obligations and accrued environmental costs	-	322	-	5,030	-	5,352
Deferred income taxes	-	-	-	5,438	(804)	4,634
Employee benefit obligations	-	1,329	-	452	-	1,781
Other liabilities and deferred credits*	1,787	7,514	826	9,271	(17,534)	1,864
Total Liabilities	5,662	19,504	3,024	28,187	(20,913)	35,464
Retained earnings	33,184	21,898	2,164	10,481	(27,985)	39,742
Other common stockholders' equity	(4,761)	18,712	6,729	26,454	(51,895)	(4,761)
Noncontrolling interests	-	-	-	69	-	69
Total Liabilities and Stockholders' Equity	$ 34,085	60,114	11,917	65,191	(100,793)	70,514

Balance Sheet	At December 31, 2018					
Assets						
Cash and cash equivalents	$ -	1,428	-	4,487	-	5,915
Short-term investments	-	-	-	248	-	248
Accounts and notes receivable	28	5,646	78	6,707	(8,392)	4,067
Investment in Cenovus Energy	-	1,462	-	-	-	1,462
Inventories	-	184	-	823	-	1,007
Prepaid expenses and other current assets	1	267	-	307	-	575
Total Current Assets	29	8,987	78	12,572	(8,392)	13,274
Investments, loans and long-term receivables*	29,942	47,062	15,199	16,926	(99,465)	9,664
Net properties, plants and equipment	-	4,367	-	41,796	(465)	45,698
Other assets	4	642	227	1,269	(798)	1,344
Total Assets	$ 29,975	61,058	15,504	72,563	(109,120)	69,980
Liabilities and Stockholders' Equity						
Accounts payable	$ -	5,098	76	7,113	(8,392)	3,895
Short-term debt	(3)	12	13	99	(9)	112
Accrued income and other taxes	-	85	-	1,235	-	1,320
Employee benefit obligations	-	638	-	171	-	809
Other accruals	85	587	35	552	-	1,259
Total Current Liabilities	82	6,420	124	9,170	(8,401)	7,395
Long-term debt	3,791	7,151	2,143	2,249	(478)	14,856
Asset retirement obligations and accrued environmental costs	-	415	-	7,273	-	7,688
Deferred income taxes	-	-	-	5,819	(798)	5,021
Employee benefit obligations	-	1,340	-	424	-	1,764
Other liabilities and deferred credits*	725	9,277	839	8,126	(17,775)	1,192
Total Liabilities	4,598	24,603	3,106	33,061	(27,452)	37,916
Retained earnings	27,512	18,511	1,113	9,764	(22,890)	34,010
Other common stockholders' equity	(2,135)	17,944	11,285	29,613	(58,778)	(2,071)
Noncontrolling interests	-	-	-	125	-	125
Total Liabilities and Stockholders' Equity	$ 29,975	61,058	15,504	72,563	(109,120)	69,980

**Includes intercompany loans.*
See Notes to Consolidated Financial Statements.

Statement of Cash Flows	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Year Ended December 31, 2019					
Cash Flows From Operating Activities						
Net Cash Provided by Operating Activities	$ 1,457	7,986	3,207	9,803	(11,349)	11,104
Cash Flows From Investing Activities						
Capital expenditures and investments	-	(2,517)	-	(5,714)	1,595	(6,636)
Working capital changes associated with investing activities	-	37	-	(140)	-	(103)
Proceeds from asset dispositions	2,374	7,047	769	1,055	(8,233)	3,012
Net purchases of investments	-	(2,803)	-	(107)	-	(2,910)
Long-term advances/loans—related parties	-	(812)	-	-	812	-
Collection of advances/loans—related parties	-	141	-	147	(161)	127
Intercompany cash management	1,060	(2,849)	1,402	387	-	-
Other	-	(149)	-	41	-	(108)
Net Cash Provided by (Used in) Investing Activities	3,434	(1,905)	2,171	(4,331)	(5,987)	(6,618)
Cash Flows From Financing Activities						
Issuance of debt	-	-	-	812	(812)	-
Repayment of debt	-	(21)	-	(220)	161	(80)
Issuance of company common stock	105	-	-	-	(135)	(30)
Repurchase of company common stock	(3,500)	-	-	-	-	(3,500)
Dividends paid	(1,500)	(4,034)	(454)	(7,097)	11,585	(1,500)
Other	4	-	(4,924)	(1,736)	6,537	(119)
Net Cash Used in Financing Activities	(4,891)	(4,055)	(5,378)	(8,241)	17,336	(5,229)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	-	(11)	-	(35)	-	(46)
Net Change in Cash, Cash Equivalents and Restricted Cash	-	2,015	-	(2,804)	-	(789)
Cash, cash equivalents and restricted cash at beginning of period	-	1,428	-	4,723	-	6,151
Cash, Cash Equivalents and Restricted Cash at End of Period	$ -	3,443	-	1,919	-	5,362

Statement of Cash Flows	Year Ended December 31, 2018*					
Cash Flows From Operating Activities						
Net Cash Provided by Operating Activities	$ 860	4,019	838	14,132	(6,915)	12,934
Cash Flows From Investing Activities						
Capital expenditures and investments	-	(980)	(603)	(5,777)	610	(6,750)
Working capital changes associated with investing activities	-	(110)	-	42	-	(68)
Proceeds from asset dispositions	3,457	666	1,926	705	(5,672)	1,082
Net sales of short-term investments	-	-	-	1,620	-	1,620
Long-term advances/loans—related parties	-	(126)	(173)	(10)	309	-
Collection of advances/loans—related parties	589	3,432	212	129	(4,243)	119
Intercompany cash management	(803)	3,504	(2,150)	(551)	-	-
Other	-	151	-	3	-	154
Net Cash Provided by (Used in) Investing Activities	3,243	6,537	(788)	(3,839)	(8,996)	(3,843)
Cash Flows From Financing Activities						
Issuance of debt	-	10	-	299	(309)	-
Repayment of debt	-	(4,865)	(53)	(4,320)	4,243	(4,995)
Issuance of company common stock	254	-	-	-	(133)	121
Repurchase of company common stock	(2,999)	-	-	-	-	(2,999)
Dividends paid	(1,363)	(1,043)	-	(6,057)	7,100	(1,363)
Other	5	(3,468)	-	(1,670)	5,010	(123)
Net Cash Used in Financing Activities	(4,103)	(9,366)	(53)	(11,748)	15,911	(9,359)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Cash	-	4	-	(121)	-	(117)
Net Change in Cash, Cash Equivalents and Restricted Cash	-	1,194	(3)	(1,576)	-	(385)
Cash, cash equivalents and restricted cash at beginning of period	-	234	3	6,299	-	6,536
Cash, Cash Equivalents and Restricted Cash at End of Period	$ -	1,428	-	4,723	-	6,151

**Revised to reclassify certain intercompany distributions from Operating Activities to 'Proceeds from asset dispositions' within Investing Activities based on the nature of the distributions. There was no impact to Total Consolidated results.*

Statement of Cash Flows	Millions of Dollars					
	Year Ended December 31, 2017					
	ConocoPhillips	ConocoPhillips Company	Burlington Resources LLC	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net Cash Provided by Operating Activities	$ 71	1,183	2,971	5,904	(3,052)	7,077
Cash Flows From Investing Activities						
Capital expenditures and investments	-	(1,663)	(4,351)	(3,795)	5,218	(4,591)
Working capital changes associated with investing activities	-	194	-	(62)	-	132
Proceeds from asset dispositions	7,765	11,146	12,178	12,796	(30,025)	13,860
Net purchases of short-term investments	-	-	-	(1,790)	-	(1,790)
Long-term advances/loans—related parties	-	(214)	(65)	(20)	299	-
Collection of advances/loans—related parties	658	1,527	389	2,196	(4,655)	115
Intercompany cash management	1,151	101	(1,341)	89	-	-
Other	-	(8)	-	44	-	36
Net Cash Provided by Investing Activities	9,574	11,083	6,810	9,458	(29,163)	7,762
Cash Flows From Financing Activities						
Issuance of debt	-	20	-	279	(299)	-
Repayment of debt	(5,459)	(4,411)	-	(2,661)	4,655	(7,876)
Issuance of company common stock	115	-	-	-	(178)	(63)
Repurchase of company common stock	(3,000)	-	-	-	-	(3,000)
Dividends paid	(1,305)	(235)	-	(2,995)	3,230	(1,305)
Other	4	(7,765)	(9,781)	(7,377)	24,807	(112)
Net Cash Used in Financing Activities	(9,645)	(12,391)	(9,781)	(12,754)	32,215	(12,356)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	1	(2)	233	-	232
Net Change in Cash and Cash Equivalents	-	(124)	(2)	2,841	-	2,715
Cash and cash equivalents at beginning of period	-	358	5	3,247	-	3,610
Cash and Cash Equivalents at End of Period	$ -	234	3	6,088	-	6,325

See Notes to Consolidated Financial Statements.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures designed to ensure information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of December 31, 2019, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Executive Vice President and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of ConocoPhillips' disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Executive Vice President and Chief Financial Officer concluded our disclosure controls and procedures were operating effectively as of December 31, 2019.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

This report is included in Item 8 on page 76 and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm

This report is included in Item 8 on page 80 and is incorporated herein by reference.

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on page 29.

Code of Business Ethics and Conduct for Directors and Employees

We have a Code of Business Ethics and Conduct for Directors and Employees (Code of Ethics), including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of our Code of Ethics on the "Corporate Governance" section of our internet website at *www.conocophillips.com* (within the Investors>Corporate Governance section). Any waivers of the Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendments to, or waivers from, the Code of Ethics that apply to our executive officers and directors will be posted on the "Corporate Governance" section of our internet website.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2020 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2020, and is incorporated herein by reference.*

Item 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2020 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2020, and is incorporated herein by reference.*

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2020 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2020, and is incorporated herein by reference.*

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2020 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2020, and is incorporated herein by reference.*

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2020 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2020, and is incorporated herein by reference.*

**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2020 Proxy Statement are not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as a part of this report.*

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements and Supplementary Data
The financial statements and supplementary information listed in the Index to Financial Statements, which appears on page 75, are filed as part of this annual report.

2. Financial Statement Schedules
Schedule II—Valuation and Qualifying Accounts, appears below. All other schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits
The exhibits listed in the Index to Exhibits, which appears on pages 188 through 196, are filed as part of this annual report.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS (Consolidated)

ConocoPhillips

Description		Millions of Dollars				
		Balance at January 1	Charged to Expense	Other(a)	Deductions	Balance at December 31
2019						
Deducted from asset accounts:						
Allowance for doubtful accounts and notes receivable	**$**	**25**	**5**	**-**	**(17)(b)**	**13**
Deferred tax asset valuation allowance		**3,040**	**7,376**	**(26)**	**(176)**	**10,214**
Included in other liabilities:						
Restructuring accruals		**48**	**(1)**	**-**	**(24)(c)**	**23**
2018						
Deducted from asset accounts:						
Allowance for doubtful accounts and notes receivable	$	4	23	-	(2)(b)	25
Deferred tax asset valuation allowance		1,254	2,067	(8)	(273)	3,040
Included in other liabilities:						
Restructuring accruals		53	70	(2)	(73)(c)	48
2017						
Deducted from asset accounts:						
Allowance for doubtful accounts and notes receivable	$	5	2	-	(3)(b)	4
Deferred tax asset valuation allowance		675	560	19	-	1,254
Included in other liabilities:						
Restructuring accruals		80	65	1	(93)(c)	53

(a)Represents acquisitions/dispositions/revisions and the effect of translating foreign financial statements.
(b)Amounts charged off less recoveries of amounts previously charged off.
(c)Benefit payments.

See Note 19—Income Taxes, in the Notes to Consolidated Financial Statements, for additional information related to our deferred tax asset valuation allowance.

CONOCOPHILLIPS

INDEX TO EXHIBITS

Exhibit Number	Description
2.1	Separation and Distribution Agreement Between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
2.2†‡	Purchase and Sale Agreement, dated March 29, 2017, by and among ConocoPhillips Company, ConocoPhillips Canada Resources Corp., ConocoPhillips Canada Energy Partnership, ConocoPhillips Western Canada Partnership, ConocoPhillips Canada (BRC) Partnership, ConocoPhillips Canada E&P ULC, and Cenovus Energy Inc. (incorporated by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 filed by ConocoPhillips on May 4, 2017).
2.3†‡	Asset Purchase and Sale Agreement Amending Agreement, dated as of May 16, 2017, by and among ConocoPhillips Company, ConocoPhillips Canada Resources Corp., ConocoPhillips Canada Energy Partnership, ConocoPhillips Western Canada Partnership, ConocoPhillips Canada (BRC) Partnership, ConocoPhillips Canada E&P ULC, and Cenovus Energy Inc. (incorporated by reference to Exhibit 2.2 to the Current Report of ConocoPhillips on Form 8-K filed on May 18, 2017; File No. 001-32395).
3.1	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987).
3.3	Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of October 9, 2015 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 13, 2015; File No. 001-32395).
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.
4.1*	Description of Securities of the Registrant.
10.1	1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.2	1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

Exhibit Number	Description
10.3	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.4	Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 001-00720).
10.5	Amendment and Restatement of ConocoPhillips Supplemental Executive Retirement Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.14 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.6	Non-Employee Director Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.18 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.7	Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.8	Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.9	Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.10.1*	Amended and Restated ConocoPhillips Key Employee Supplemental Retirement Plan, dated January 1, 2020.
10.10.2	Eighth Amendment to Retirement Plans as amended and restated effective January 1, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2018; File No. 001-32395).
10.11.1*	Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title I, dated January 1, 2020.
10.11.2*	Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated January 1, 2020.
10.12	2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.13	Amendment and Restatement of 1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.14	Amendment and Restatement of 1998 Key Employee Stock Performance Plan of ConocoPhillips (incorporated by reference to Exhibit 10.28 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

Exhibit Number	Description
10.15	Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.16.1	Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of the Annual Report of ConocoPhillips Holding Company on Form 10-K for the year ended December 31, 1999; File No. 001-14521).
10.16.2	Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.16.3	Phillips Petroleum Company Grantor Trust Agreement, dated June 1, 1998 (incorporated by reference to Exhibit 10.17.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.16.4	First Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated May 3, 1999 (incorporated by reference to Exhibit 10.17.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.16.5	Second Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated January 15, 2002 (incorporated by reference to Exhibit 10.17.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.16.6	Third Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated October 5, 2006 (incorporated by reference to Exhibit 10.17.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.16.7	Fourth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 1, 2012 (incorporated by reference to Exhibit 10.17.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.16.8	Fifth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 20, 2015 (incorporated by reference to Exhibit 10.17.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.17.1	ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.17.2	First and Second Amendments to the ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
10.18	ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.19.1*	Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title I, dated January 1, 2020 (incorporated by reference to Exhibit 10.12.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).

Exhibit Number	Description
10.19.2*	Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated January 1, 2020 (incorporated by reference to Exhibit 10.12.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.20	Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, effective January 1, 2014 (incorporated by reference to Exhibit 10.21 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2013; File No. 001-32395).
10.21	ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.22.1	2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix C of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2004 Annual Meeting of Shareholders; File No. 000-49987).
10.22.2	Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.22.3	Form of Performance Share Unit Award Agreement under the Performance Share Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.23	Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007 (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2007; File No. 001-32395).
10.24	2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2009 Annual Meeting of Shareholders; File No. 001-32395).
10.25.1	2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2011 Annual Meeting of Shareholders; File No. 001-32395).
10.25.2	Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, effective February 9, 2012 (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2012; File No. 001-32395).
10.25.3	Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 18, 2012 (incorporated by reference to Exhibit 10.26.5 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
10.25.4	Form of Performance Share Unit Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.6 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).

Exhibit Number	Description
10.25.5	Form of Performance Share Unit Agreement—Canada under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
10.25.6	Form of Restricted Stock Award Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.8 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
10.25.7	Form of Stock Option Award Agreement under the Stock Option and Stock Appreciation Rights Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013 (incorporated by reference to Exhibit 10.26.9 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2012; File No. 001-32395).
10.25.8	Form of Make-Up Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated January 1, 2012 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2013; File No. 001-32395).
10.25.9	Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.25.10	Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.25.11	Form of Key Employee Award Agreement, as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.14 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.25.12	Form of Performance Period IX Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.25.13	Form of Performance Period IX Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.25.14	Form of Performance Period X Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014 (incorporated by reference to Exhibit 10.5 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).

Exhibit Number	Description
10.25.15	Form of Performance Period XIV Award Agreement, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.25.16	Form of Performance Period XIV Award Agreement—Canada, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016 (incorporated by reference to Exhibit 10.26.24 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2015; File No. 001-32395).
10.25.17	Form of Inducement Grant Award Agreement under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated March 31, 2014 (incorporated by reference to Exhibit 10.11 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2014; File No. 001-32395).
10.25.18	Form of Performance Share Unit Award Terms and Conditions for Performance Period 18, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by reference to Exhibit 10.26.24 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395).
10.25.19	Form of Performance Share Unit Award Terms and Conditions for Performance Period 18 for eligible employees on the Canada payroll, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by reference to Exhibit 10.26.25 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395).
10.26.1	2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 14, 2014; File No. 001-32395).
10.26.2	Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 3, 2015 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2015; File No. 001-32395).
10.26.3	Form of Retention Award Terms and Conditions, as part of the Restricted Stock Unit Award, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2015; File No. 001-32395).
10.26.4	Form of Non-Employee Director Restricted Stock Units Terms and Conditions, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.26.5	Form of Non-Employee Director Restricted Stock Units Terms and Conditions – Canadian Non-Employee Directors, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.4 to the Quarterly

Exhibit Number	Description
	Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.26.6	Form of Non-Employee Director Restricted Stock Units Terms and Conditions – Norwegian Non-Employee Directors, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016 (incorporated by reference to Exhibit 10.5 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.26.7	Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395).
10.26.8	Form of Performance Share Unit Award Terms and Conditions for Performance Period 17, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395).
10.26.9	Form of Performance Share Unit Award Terms and Conditions for Performance Period 17 for eligible employees on the Canada payroll, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395).
10.26.10	Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017 (incorporated by reference to Exhibit 10.4 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2017; File No. 001-32395).
10.26.11	Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Executive Restricted Stock Unit Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by reference to Exhibit 10.27.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395).
10.26.12	Form of Key Employee Award Terms and Conditions for eligible employees on the Canada payroll, as part of the ConocoPhillips Executive Restricted Stock Unit Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by reference to Exhibit 10.27.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395).
10.26.13	Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Restricted Stock Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018 (incorporated by reference to Exhibit 10.27.14 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395).
10.26.14	Form of Retention Award Terms and Conditions, 2017 revision, as part of the Restricted Stock Unit Award, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27.15 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2017; File No. 001-32395).

Exhibit Number	Description
10.26.15	Form of Key Employee Award Terms and Conditions as part of the ConocoPhillips Restricted Stock Unit Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2019.
10.27*	Amended and Restated 409A Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips, dated January 1, 2020 (incorporated by reference to Exhibit 10.8 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.28	Amendment, Change of Sponsorship, and Restatement of Certain Nonqualified Deferred Compensation Plans of ConocoPhillips, dated April 19, 2012 (incorporated by reference to Exhibit 10.10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.29	Amendment and Restatement of the Burlington Resources Inc. Management Supplemental Benefits Plan, dated April 19, 2012 (incorporated by reference to Exhibit 10.9 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended June 30, 2012; File No. 001-32395).
10.30	Amendment and Restatement of Deferred Compensation Trust Agreement for Non-Employee Directors of Phillips Petroleum Company, dated June 23, 1995 (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2016; File No. 001-32395).
10.31	Indemnification and Release Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.32	Intellectual Property Assignment and License Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.2 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.33	Tax Sharing Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.3 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.34	Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 12, 2012 (incorporated by reference to Exhibit 10.4 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.35	Transition Services Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012 (incorporated by reference to Exhibit 10.5 to the Current Report of ConocoPhillips on Form 8-K filed on May 1, 2012; File No. 001-32395).
10.36	ConocoPhillips Clawback Policy dated October 3, 2012 (incorporated by reference to Exhibit 10.3 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2012; File No. 001-32395).
10.37	Term Loan Agreement, between ConocoPhillips, as borrower, ConocoPhillips Company, as guarantor, Toronto Dominion (Texas) LLC, as administrative agent and the banks party thereto, with TD Securities (USA) LLC, as lead arranger and bookrunner, dated March 18, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report of ConocoPhillips on Form 8-K filed on March 21, 2016; File No. 001-32395).

Exhibit Number	Description
10.38	Company Retirement Contribution Make-Up Plan of ConocoPhillips, dated December 28, 2018 (incorporated by reference to Exhibit 10.39 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2019; File No. 001-32395).
10.40	Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Targeted Variable Long Term Incentive Program, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated September 23, 2019 (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended September 30, 2019; File No. 001-32395).
21*	List of Subsidiaries of ConocoPhillips.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32*	Certifications pursuant to 18 U.S.C. Section 1350.
99*	Report of DeGolyer and MacNaughton.
101.INS*	Inline XBRL Instance Document.
101.SCH*	Inline XBRL Schema Document.
101.CAL*	Inline XBRL Calculation Linkbase Document.
101.DEF*	Inline XBRL Definition Linkbase Document.
101.LAB*	Inline XBRL Labels Linkbase Document.
101.PRE*	Inline XBRL Presentation Linkbase Document.
104*	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

* *Filed herewith.*
† *The schedules to this exhibit have been omitted pursuant to Item 601(b)(2) of Regulation S-K. ConocoPhillips agrees to furnish a copy of any schedule omitted from this exhibit to the SEC upon request.*
‡ *ConocoPhillips has previously been granted confidential treatment for certain portions of this exhibit pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended.*

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.

CONOCOPHILLIPS

February 18, 2020

/s/ Ryan M. Lance
Ryan M. Lance
Chairman of the Board of Directors
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 18, 2020, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

Signature	Title
/s/ Ryan M. Lance Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer (Principal executive officer)
/s/ Don E. Wallette, Jr. Don E. Wallette, Jr.	Executive Vice President and Chief Financial Officer (Principal financial officer)
/s/ Catherine A. Brooks Catherine A. Brooks	Vice President and Controller (Principal accounting officer)

/s/ Charles E. Bunch Charles E. Bunch	Director
/s/ Caroline M. Devine Caroline M. Devine	Director
/s/ Gay Huey Evans Gay Huey Evans	Director
/s/ John V. Faraci John V. Faraci	Director
/s/ Jody Freeman Jody Freeman	Director
/s/ Jeffrey A. Joerres Jeffrey A. Joerres	Director
/s/ William H. McRaven William H. McRaven	Director
/s/ Sharmila Mulligan Sharmila Mulligan	Director
/s/ Arjun N. Murti Arjun N. Murti	Director
/s/ Robert A. Niblock Robert A. Niblock	Director